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SPECIALIZED FOR EXPLORATION, DRILLING AND PRODUCING OPERATIONS AND MANAGEMENT

MAY
1960

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How to deepen shallow wells 137
Aluminum platforms pay off 139
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What's ahead for Mexico? 162

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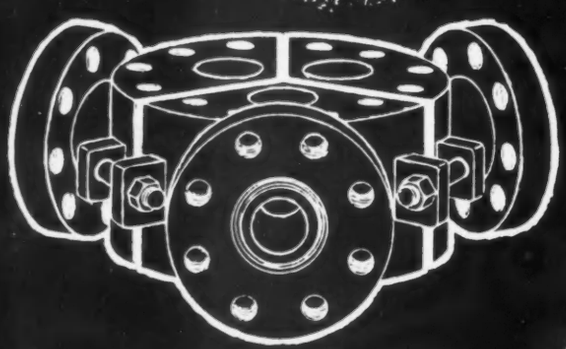

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WORLD OIL

A Gulf Publishing Company Publication

SPECIALIZED FOR EXPLORATION, DRILLING AND PRODUCING OPERATIONS AND MANAGEMENT

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A Quick Look at this issue

BUSY OIL MEN: To help you put first things first, scan these time-saving digests on this and the following pages, checking ☑ those you want to read first.

GILBERT M. WILSON, WORLD OIL's Western District Editor, South Pasadena, Calif., recently spent a month in Houston editing the API Section of this issue. This section—including eight of the outstanding drilling, production and economics papers presented at four recent API district meetings—is designed to supply you with a permanent record of these valuable papers if you attended these meetings or to acquaint you with the papers presented if you did not attend.

Gilbert M. Wilson

In addition, abstracts of 21 other papers and listings of 26 more are included in this section from the following meetings:

- API Southwest District Meeting, Dallas, March 2-4.
- API Southern District Meeting, San Antonio, March 16-18.
- API Mid-Continent District Meeting, Wichita, Kan., March 30-April 1.
- API Rocky Mountain District Meeting, Casper, Wyo., April 20-22.

Also in this issue, you will find the most current information available on industry economic developments, promising oil and gas areas, new exploration methods and ideas, plus more top quality technical-operating drilling and production articles.

All this is yours for the reading on the following pages of WORLD OIL.

☐ **Slim hole completions reduce development costs . . .** Hudson's Bay Oil and Gas Company has completed 36 slim hole wells in Canada using 2⅞-inch tubing as casing. Cost savings have averaged 35 percent for single wells and 18 percent for duals, compared with conventional sized wells. For a highly informative description of small diameter cased well pro-

WORLD OIL published every month except semi-monthly in February and August. Second class postage paid at Houston, Texas. ©Gulf Publishing Co. 1960

duction string design, cementing, logging, perforating, fracturing, and pumping, turn to.....**Page 91**

☐ **How to control blowouts (Part 1) . . .** Here's a method of killing threatened blowouts which goes beyond the usual advice of "put the well on choke and raise the mud weight." This series not only gives a method for determining the choke size and mud weight required, but tells how to handle drilling breaks and what action to take when a blowout threatens during a trip. .**Page 97**

☐ **How to evaluate current finding costs . . .** Traditional accounting concepts do not tell an oil company the cost of replacing its crude oil inventory. Nor do they reflect future profits. However, by using available data and deriving replacement cost trends, an oil company can plan wisely its exploration and production programs, and gain some knowledge of future profits. A new approach in determining such information is described on .....**Page 103**

☐ **Stock tank vapor recovery increases lease income . . .** Recovering rich stock tank vapors with small, automatically operated compressor units is creating lease income that otherwise would be lost. Consolidating lease tank batteries, a comparatively recent trend, is making such vapor recovery operations more attractive. For detailed information, plus a typical computation of the price paid to the producer for such vapors, turn to.....**Page 107**

☐ **Turbodrilling: What is its status today? . . .** Until further improvements are made in rock bits and diamond bits to be used with it, little is to be gained from further testing of the tool. Except in very limited applications, it cannot compete economically with good rotary drilling practices. For a timely summary of extensive field test results, the economics both for and against turbodrill use, and a look at its future possibilities, turn to .....**Page 111**

☐ **Sucker rod failures cut 56 percent in 6 years in Mid-Continent . . .** Sucker rod failures were reduced 56 percent in six years by Cities Service Oil Company in its West Kansas operations. Rod breaks were cut from 1,790 in 1953 to 789 in 1959, and the downward trend continues. This is attributed to a program of corrosion control, proper rod box make-up and care, dynamometer studies to determine optimum well loads, and conducting of tests to determine the best rod steels. Saving in rod expenditures along amounts to $10,000 per year. See .....**Page 116**

☐ **New test tool samples several zones in one trip . . .** A new formation testing tool, with but a single trip to the drill pipe, obtains reservoir pressure readings and samples of formation fluids in multiple zones or sections within a single formation. For complete details on the new tool, including a discussion of its operation and applications, turn to.....**Page 120**

Coming in June . . .

A new look at oil and gas in Southeast U.S.

What is the oil and gas potential of this 11-state* area? Where are the most active exploration sites? What is the current status of drilling and producing activity? Do the latest geologic appraisals reveal any promising new areas? What are the latest drilling and production practices?

Answers to these questions, plus more than 20 tectonic and basin maps, columnar sections, correlation charts, and informative tables will be included in the most authoritative, complete report yet published on the Southeast United States.

Articles covering the above subjects will be bylined by more than 15 top consulting geologists, state geologists, geochemists, and engineers in the area. And these will only be a portion of the outstanding technical and economic articles that will be yours for the reading in your June WORLD OIL.

* (Maryland, Kentucky, West Virginia, Virginia, Tennessee, North Carolina, South Carolina, Georgia, Mississippi, Alabama, Florida.)

Plus abstracts of 21 other papers

☐ **Stripper lease ACT can save you money . . .** The greatest potential for automation in producing operations lies in its adaptation to small leases. Relatively low cost LACT units now are available which are rugged, accurate and capable of long, unattended operation with a minimum of maintenance. Here is a detailed description of a positive displacement meter equipped LACT unit which is suited for use on leases producing 30-200 barrels of oil per day. See. . .**Page 123**

☐ **Sinclair completes world's first quintuple well . . .** Sinclair Oil and Gas Company has completed a quintuple string well 40 miles offshore from the coast of Louisiana in 72 feet of water. Six hydraulic packers and five strings of 2⅜-inch OD tubing were used. For complete details on this unique completion, turn to .....**Page 132**

☐ **How to establish well-density control . . .** Careful preparation of the initial contract is the key to successful well-density control. Observance of certain precautions can save both time and money. For a highly informative description of the three most common contractural methods, plus many valuable tips to use in setting them up, turn to.....**Page 133**

☐ **How to deepen small cased wells with cable tools . . .** An Oklahoma operator has successfully used cable tools to deepen a shallow well equipped with 4½-inch casing. Approximately 250 feet of 3¾-inch hole

was drilled below the 4½-inch casing seat. After setting 2½-inch casing, an additional 37 feet of 2¼-inch hole was drilled to test a lower sand. See **Page 137**, for complete details on this inexpensive method.

☐ **Aluminum platforms prove successful in Lake Maracaibo . . .** Aluminum template drilling platforms have been in use in this area for two years, and from the latest laboratory analysis, they should have a life expectancy of more than 50 years. Full details on the prefabrication, installation and evaluation of aluminum platforms are presented on.....**Page 139**

☐ **New waterflood features unitized equipment layout . . .** Shell Oil Company's new Dominguez field waterflood installation is designed for maximum ease of operation, maintenance and expansion. Also, the simplified design of the system has contributed to reduced operating costs. See **Page 143** for complete details on the installation, including schematic drawings.

☐ **New discoveries spark Dakota play in northern New Mexico . . .** One of the hottest oil and gas areas in the United States during recent years—the Blanco region of northern New Mexico—is expected to continue to grow at a record-breaking clip during 1960. Of particular interest is the new Dakota play. For a timely review of this area of unusually high wildcat success ratios, plus a map locating the most active exploration areas, turn to.....**Page 149**

☐ **Inverse filtering helps solve problem of offshore multiples . . .** The "singing" phenomenon which appears on some marine seismograms from the Persian Gulf and other difficult offshore areas, has long plagued marine seismic work. Water reverberations cause valid reflections from depth to be partially or almost totally obscured. New data-processing techniques are being used to erase (in effect) water reverberations, and permit valid data to be presented in about the same form as shooting on dry land. Also, this marine experience with inverse filtering may have onshore applications. For more details on this new method, turn to.....**Page 156**

☐ **Mexico has active program of oil and gas development . . .** Pascual Gutiérrez Roldán, general manager of petróleos Mexicanos, stands here with hand on desk. At his office in Mexico City he told representatives of U.S. oil industry publications about oil and gas in Mexico. Back of him is Antonio Vargas MacDonald, public relations director of Pemex. Standing at right is L. J. Logan, associate editor of WORLD OIL. General information on Mexico's petroleum industry, as obtained on a tour of installations throughout the country, appeared in WORLD OIL of April 1960 on Page 122. For more detailed information on fields and properties visited, see article in this issue.....**Page 162**

Oil Industry In Brief

Here are the latest industry trends, revealed by WORLD OIL and industry research:

Demand to increase. Demand for all oils expected to increase 4.2 percent in second quarter, 5.1 percent in third quarter and 4.1 percent in final quarter. Year's increase: 3.6 percent . . . See Page 25.

Inventories decline. On March 31, stocks of all oils totaled 750.6 million barrels, down 8.5 million or 1.1 percent from same date in 1959 . . . See Page 25.

Markets weak. Persistent imbalance between supply and demand continues to weaken crude oil prices. However, plans for tight proration and reduced refinery runs should improve picture considerably in coming months . . . See Page 25.

Rig totals increase. The 3,760 rigs operating on March 31 reflected a 179-rig increase over February's end, but total still was 359 rigs less than 4,119 rigs operating on same date in 1959 . . . See Page 29.

Less footage drilled. Footage drilled dropped 18,250 feet per day during March to 464,510 feet per day . . . See Page 29.

Costs increase. In past seven years, finished steel prices have increased 37 percent, wages have gone up 30 percent, oil field machinery prices are up 26 percent, and oil well casing prices have risen 41 percent, while crude oil prices have increased less than 10 percent . . . See Page 15.

Four-year trend. Compared with first quarter 1956, same 1960 period was down 26.8 percent in new well completions, 24.1 percent in total wildcats, 23.1 percent in footage drilled, and 23 percent in total operating rigs . . . See Page 29.

Oil Men Know Thompson's

FULL LINE OF ROD PUMPS . . . and "FULL-LINE" Service!

Full-Line Service

- Pick-up and delivery.
- All factory stores carry complete stock . . . all Thompson pump models and replacement parts. No delay!
- All are equipped to make any repairs.
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B-H Pump Service, Selman City, Texas
Happy Co., Salem, Illinois

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GPC PUBLICATIONS

WORLD OIL (formerly The Oil Weekly) and The COMPOSITE CATALOG for the drilling-producing industry.
PIPE LINE INDUSTRY and The PIPE LINE CATALOG for the oil and gas pipe line industry.
PETROLEUM REFINER and The REFINERY CATALOG for the oil, gas and petrochemical processing industry.

Indexed by Industrial Arts Index and Engineering Index

Looking Ahead

Independent producers tell how to cut costs . . . Recent survey of 6,000 Independent Petroleum Association of America members revealed, among many others, the following valuable cost-cutting tips:

Exploration: Relinquish lease acreage where no evaluation is expected during the year—interchange of seismic and other information among operators—reduce number of logs acquired, with limitations on their relationship to an individual's operations—more carefully evaluate geological, surface or seismic picture prior to drilling—adequately and positively test all indications of possible production.

Drilling: Replies indicated accelerated trend toward slim-hole drilling and use of small size tubular goods in completion—also, drilling contracts are being revised with operator assuming greater proportion of contractors' risks—pre-drilling conferences and close study of all information on specific areas is reducing per foot drilling cost and saving time.

Production: Use of roustabout help to change pump or lines, or to set the crank back, is being discarded in one instance where four pumpers are employed—Where producing leases are removed from a concentrate of operations, one firm is contracting its pumping while two others make use of the same pumper on part-time basis; previously every operator had his own pumpers—Adjustment of pump schedules, combining of tank batteries and installation of automatic custody transfer units also were listed as ways to cut costs.

"Young" crude oil? . . . Concepts of hydrocarbons genesis are changing, and it may not take so long for crude oil to develop and accumulate as previously thought. Look for more oil companies to seek "young" oil in Pleistocene horizons.

Looking ahead in Washington . . . Democratic presidential hopeful Stuart Symington has expressed his views on percentage depletion: He believes provision should be reduced from 27½ to 15 percent, as per his previous stands on the issue in 1958 and 1959 (See Editorial, Page 15).—**Current opinions** are that watered down versions of coal's proposed fuels policy study will get by the Senate, but will bog down in the House—**Recent residual import hike** has spurred coal group to ask for "immediate and impartial study of nation's total fuel requirements."—

Humble Oil and Refining Company is turning the tables on two California gas distributors by challenging their applications for higher gas rates. Distributors often intervene in FPC cases to attack proposed field price hikes, but this is the first time, as far as is known, that a producer has reversed the procedure.

Dynamic decade ahead . . . Three top industry spokesmen have inserted rays of hope into industry gloom over current economic conditions:

Paul Kayser, president, Western Natural Gas Company . . . staggering energy demands in the next ten years will overcome current chaotic price problems of petroleum energy. Global economic revolution will bring back all energy at level high enough to keep the petroleum industry in business.

Eugene Holman, board chairman, and M. J. Rathbone, president, Standard Oil Company (New Jersey) . . . Prospects are that demand for all types of energy will continue to increase strongly in the sixties, and that oil and gas combined will share somewhat more than proportionately in filling this demand. The oil industry is passing through a period of imbalance between supply and demand, and such periods can be expected again in this dynamic industry.

First quintuple completion . . . Sinclair and associates recently made the industry's first quintuple completion 40 miles offshore from Louisiana's St. Mary Parish. Five parallel 2-inch tubing strings with six packers were run inside 9⅝-inch casing. Well was completed in six zones, five of which can be produced simultaneously (See **Page 132**).

Good Wells Make Good News

A Report on Recent Treatments Using Abrasijet

May, 1960

Abrasijet* — a Dowell-developed abrasive jetting service — uses high velocity streams of sand-laden fluid to perforate casing or clean hole walls. Here are four recent examples of the kind of results many operators have experienced.

- **Harrison County, East Texas** (New Oil Well) Pay zone was the highly soluble Glen Rose. Since the water table was only six feet below the producing interval, operator was afraid to use conventional perforating. Abrasijet was used to perforate from 4492 to 4493 feet with a vertical cut and from 4494 to 4495 feet with a vertical cut. 5000 gallons of 5 per cent acid and 5000 pounds of sand were jetted. Following Abrasijet, well tested 192 bopd without further treatment. This is considerably better than the 125 bopd average test of wells in the area that have been perforated with explosives and then acidized.

- **Lea County, New Mexico** (New Oil Well) This well was to be completed in the Grayburg and San Andres between 4501 and 4734 feet. Abrasijet was used to perforate because fracturing pressures of 6000 to 8500 psi had been required after conventional perforating. 55 levels were jetted allowing about four minutes at each level. Total jetting time was 216 minutes. Well was successfully fractured at only 4900 psi. Production is top allowable.

- **Kingman County, Kansas** (New Oil Well) This well was to be completed in the Mississippi lime at 4428 and 4434 feet. Other nearby wells had very high gas/oil ratios and were completed as gas wells. The operator wanted to get a low gas/oil ratio so this well could be completed for oil. Abrasijet was used to perforate at 4428 and 4434 feet. No further treatment was necessary. On test, the well swabbed 22 boph. Gas lift equipment was installed and a good well with a low gas/oil ratio resulted.

- **Montgomery County, Southeast Texas** (Old Oil Well) This well had depleted a lower zone of the Conroe sand, so the operator set a five-inch liner in the seven-inch casing before re-completing. Abrasijet was selected to perforate because of the heavy steel and cement sheath. Two perforations were jetted at each foot from 5019 to 5023 feet. 7500 gallons of salt water and 7400 pounds sand were used for jetting. Well came in flowing 54.5 bopd through a 10/64-inch choke. Gas/oil ratio was 507/1.

Many times, Abrasijet is the most economical way to perforate if a well is to be stimulated by fracturing or acidizing. Often, it has proved to be the only way to complete a problem well successfully. For service or detailed information, dial Dowell. Dowell services and products are offered from more than 150 offices and stations in the United States, Canada, Venezuela and Argentina. Dowell, Tulsa 1, Oklahoma.

*Dowell Service Mark

Services for the oil industry DOWELL

DIVISION OF THE DOW CHEMICAL COMPANY

Is industry becoming a political image?

THE SCRAMBLE for presidential and vice presidential votes is under way—and let economic reality take the hindmost.

Political speeches and front page newspaper stories already are laying groundwork that will make a tough job tougher for the oil and gas industry during the next session of Congress.

Two examples: Senator Hubert Humphrey has called public attention to the need to "eliminate the $5 billion in tax loopholes." Hidden between those seven words is a plan to reduce the depletion provision. Senator Stuart Symington, in a recent press interview, reaffirmed his belief that the depletion provision should be cut from 27½ to 15 percent. This, of course, is in accordance with his previous stands on the issue in 1958 and 1959.

As usual, there is, and will be, a loud silence when it comes to making pledges to reduce government waste, cut back excessive federal control or to ease the excessive gasoline tax that is eating into the pocketbooks of American motorists.

Just as noticeable will be the silence regarding ways to ease increased industry labor and equipment costs, tightening profit margins or the need for a higher, not lower depletion percentage. It appears that such pledges are not what the public wants to hear—or are not the kind that produce votes.

Can you imagine one of the political candidates making such public statements as:

"Within the next 40 years population totals will double in the United States. Thus, the oil and gas industry will need every possible incentive to find enough reserves to meet soaring demand."

Or, "In the past seven years the price of finished steel has gone up 37 percent, wages have increased 30 percent, and oil field machinery has increased 26 percent, yet the price of crude oil has increased less than 10 percent. Ways must be found to ease the cost-price squeeze so the industry will have the incentive needed to continue to find enough reserves to meet our rapidly increasing energy requirements."

Or, "Unless the current depletion provision remains intact, slackened industry operations will quickly cut deep into domestic crude oil reserves. If this occurs, the nation will be at a decided disadvantage. The United States needs the oil. And the 27½ percent depletion provision is a major reason why this country never has had inadequate supplies. This should be reason enough not to upset the apple cart."

Obviously, such realistic economic statements will not be forthcoming during this presidential election year. Yet, they must be presented to the public.

Positive action must be taken to help the public understand that the political image of industry is not necessarily the true image. The economic problems, a true profit picture, future demands on industry—all of these must be completely and simply defined.

How can this be done? By more active industry participation in local, state and national politics. By properly informing employes, stockholders and customers. By explaining the tangible benefits that grow out of a successful industry, unhampered by excessive federal control.

This is the year that voluminous politically based economic statements will be scatter-gunned to the American voters. Thus, this is the year that more attention than ever should be given to acquainting the public with industry's side of the story.

Then, when the votes have been cast, perhaps the public will have retained industry's image of industry —not the politicians'.

Most Anyone Can Put Holes In A Pipe

Some oil men think that completing a well means nothing more than putting holes in a pipe. Most anybody can do that.

But Welex Completion Services offer more than holes in the pipe. That's why selection of Welex to complete your well is so important.

Welex's well-rounded Completion Services go far beyond "just putting holes in pipe." To you, this may mean the difference between winning and losing a million dollar gamble a mile or two or more underground.

Why is Welex the best choice? There are many reasons. For example:

What if the well presents special completion problems—problems such as high temperatures or high pressures? Welex has a large staff of specially trained engineers, ready to tackle each individual well and map out the most effective completion program.

What about cost? If you want nothing more than holes in your pipe, you may find someone cheaper. But why risk a million dollar investment by choosing a company a few dollars cheaper in price but thousands of dollars short in experience and know-how.

What about new services? Through the years Welex has always led the field in offering new, proven Completion Services. As originator of jet perforating, Welex has more experience and technical know-how in this field than any other company. Welex's research engineers already are working on new developments that will become standards of the industry in the future, just as many of their past developments are now standards.

What about different types of wells? Here's another important question—and answer which again makes Welex the best choice. Welex is the *only* wireline service company offering a *complete* selection of Completion Services for *every* well condition, whether cased hole, through tubing, tubingless or open hole.

And speaking of hole conditions, Welex has the most complete selection of perforating guns for every type of hole. Let Welex's experienced engineers solve your completion problems.

Experience?

There's no substitute for experience.

In well completions, the company with the most experience is the logical choice.

When you select Welex, originator of jet perforating, you're getting the company that engineered and developed most of today's modern Completion Services. Welex has the know-how, gained from research and field experience, to solve any completion problem.

And for optimum size hole perforations and deepest penetration, proven jet charges from Welex research facilities out-perform all others—both in laboratory tests and in your well.

W E L E X , I N C .

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Slow demand keeps markets unsettled

PETROLEUM INDUSTRY markets have continued weak, because of persisting imbalance between supply and demand. But there are some favorable factors in the situation. And it seems reasonable to hope that more stable markets can be achieved in coming months, if crude oil production and refinery runs are strictly held down in line with demand, which so far this year has been lower than expected.

Demand. Total demand for petroleum was disappointing in the first quarter of 1960. It was 70,000 barrels a day or 7/10 of 1 percent lower than in the like period of 1959, instead of 209,000 barrels daily or 2 percent greater, as forecast by the Bureau of Mines. (WORLD OIL, Feb. 15, 1960, Page 82.) Actual demand therefore was about 280,000 barrels a day less than forecast.

Demand for gasoline in this year's first quarter was down 173,000 barrels daily or 4.6 percent, instead of being up 131,000 barrels or 3.5 percent as forecast. Actual demand consequently was about 300,000 barrels a day less than forecast.

Residual fuel oil demand was off about 100,000 barrels daily or 4.8 percent, a somewhat smaller decrease than that of 6.1 percent predicted. Kerosine demand was the same as a year ago, as expected.

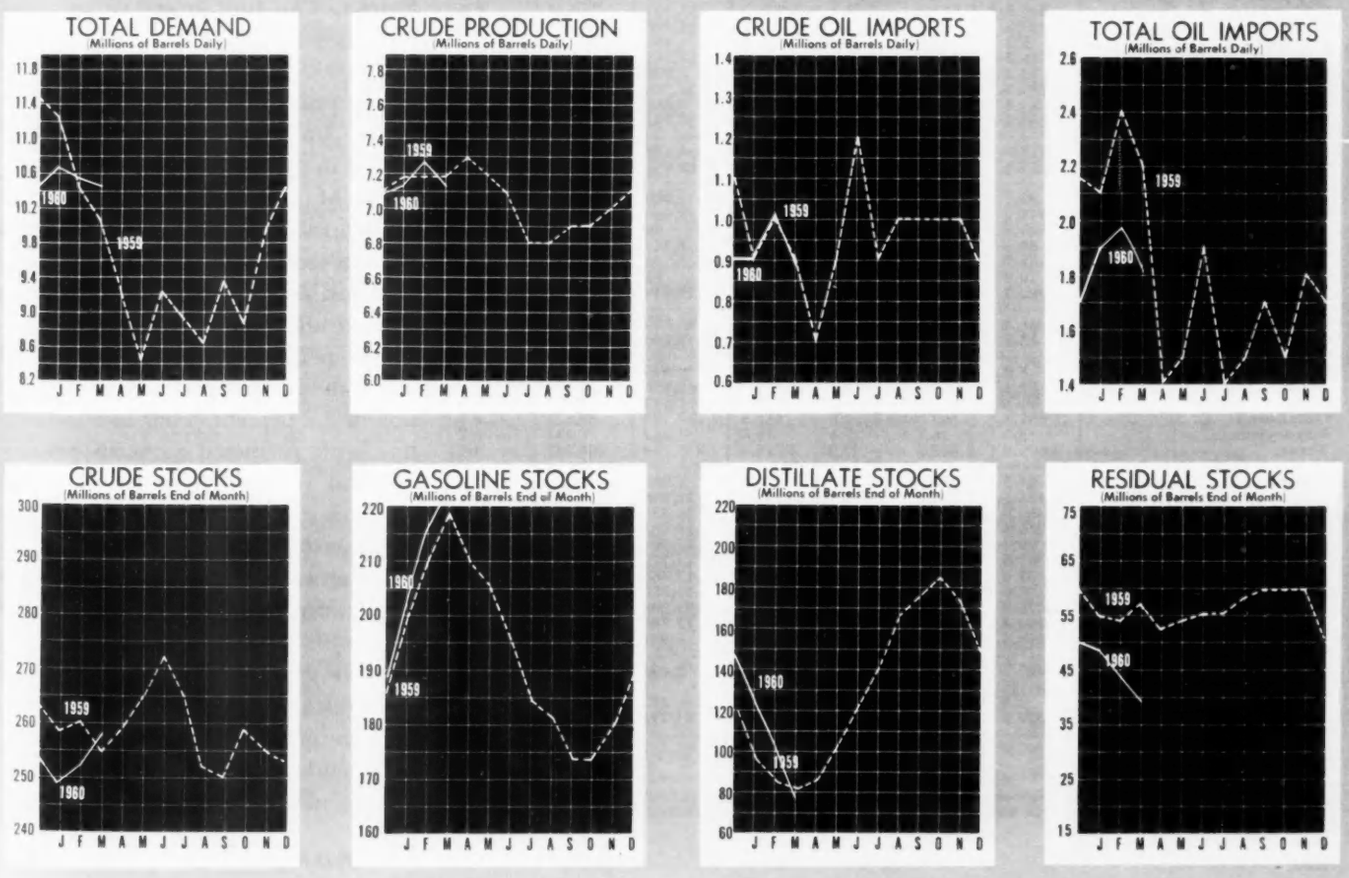
Distillate fuel oil demand finally showed an increase of 51,000 barrels daily of 1.9 percent, approximately as expected; but only because March was exceptionally cold. Distillate demand had lagged badly in January and February, and prices declined. The cold weather of March was too late to be of much help to distillate prices and the industry's first quarter earnings.

Outlook. If petroleum demand henceforth should equal the forecasts, it would average 10,009,000 barrels daily for 1960, an increase of 3.6 percent over that of 9,662,000 daily recorded in 1959. (The original forecast for 1960, including an expected gain in the first quarter, was 10,080,000 barrels daily. That would have been an increase of 4.3 percent.)

For the second quarter of 1960 an increase of 4.2 percent is forecast; for the third quarter 5.1 percent; and for the fourth quarter 4.1 percent. Fulfillment of those forecasts in coming quarters would represent an encouraging improvement over the disappointing experience of the initial quarter.

A disturbing thing about first quarter results was the decrease instead of increase in gasoline demand, which fell 300,000 barrels a day short of expectations. The drop was not easy to

Petroleum Trends...



U. S. Petroleum Demand and Supply (Thous. Bbls. Daily)

ITEM	MARCH 1960	MARCH 1959	% Diff.	Feb. 1960	JANUARY-MARCH 1960	JANUARY-MARCH 1959	% Diff.
DEMAND							
All Oils, Total Demand	10,440	10,052	+ 3.9	10,595	10,568	10,638	— 0.7
Domestic Demand	10,240	9,811	+ 4.4	10,370	10,363	10,389	— 0.3
Export Demand	200	241	—17.0	225	205	248	—17.3
Gasoline, Total Demand	3,730	3,879	— 3.8	3,666	3,582	3,755	— 4.6
Distillate, Total Demand	2,804	2,214	+26.6	2,535	2,719	2,668	+ 1.9
Kerosine, Total Demand	477	346	+37.9	441	466	466	
Residual, Total Demand	1,982	1,999	— 0.8	1,940	1,989	2,088	— 4.8
Other Oils, Total Demand	1,447	1,614	—10.3	2,013	1,812	1,661	+ 9.1
CHANGE IN STOCKS							
All Oil, Change in Stocks	—594	+235	.....	—410	—532	—338	.....
NEW SUPPLY							
Total New Supply	9,846	10,288	— 4.3	10,185	10,036	10,299	— 2.6
Domestic Production, Total	8,039	8,070	— 0.4	8,215	8,141	8,081	+ 0.7
Crude Oil	7,104	7,188	— 1.2	7,275	7,202	7,202	
Natural Gas Liquids	935	882	+ 6.0	940	939	879	+ 6.8
Imports, Total	1,807	2,218	—18.5	1,970	1,895	2,218	—14.6
Refined Products	911	1,311	—30.5	956	952	1,260	—24.5
Crude Oil, Total	896	907	— 1.2	1,014	943	958	— 1.6
Crude, East of Calif.	664	705	— 5.8	759	708	758	— 6.6
CRUDE RUNS							
Crude Runs to Stills	7,879	8,207	— 4.0	8,081	8,080	8,190	— 1.4
Domestic Crude	6,899	7,276	— 5.2	7,134	7,129	7,239	— 1.5
Foreign Crude	980	931	+ 5.3	947	951	951	.....

U. S. Stocks of Oils (Million Bbls. at End of Month)

KIND OF OIL	TOTAL IN U.S. Mar. 1960	TOTAL IN U.S. Mar. 1959	% Diff.	TOTAL IN U.S. Feb. 1960	EAST OF CALIFORNIA Mar. 1960	EAST OF CALIFORNIA Mar. 1959	% Diff.	EAST OF CALIFORNIA Feb. 1960
All Oils	750.6	759.1	— 1.1	769.0	.....	.....	.....	.....
Crude Oil	258.0	254.9	+ 1.2	253.0	223.9	214.5	+ 4.4	219.4
Gasoline	225.6	218.6	+ 3.2	217.5	193.9	188.8	+ 2.7	186.9
Distillate Fuel Oil	75.1	80.7	— 6.9	104.7	64.2	69.5	— 7.6	93.6
Kerosine	17.3	18.7	— 7.5	21.1	16.3	18.3	—10.9	20.8
Residual Fuel	39.1	57.2	—31.7	44.9	24.9	29.2	—14.7	28.9
Other Oils	135.5	129.0	+ 5.0	127.8	.....	.....	.....	.....

U. S. Crude Oil Production, by States (Thous. Bbls.)

STATE or DISTRICT	Daily Average for Month Mar. 1960	Mar. 1959	% Diff.	Feb. 1960	Total, January-March 1960	1959	% Diff.
Alabama	19.3	10.6	+ 82.1	19.2	1,649	1,065	+ 54.8
Arkansas	83.6	73.4	+ 13.9	82.0	7,154	6,902	+ 3.7
California	825.9	843.1	— 2.1	828.4	75,321	75,819	— 0.7
Colorado	129.6	127.2	+ 1.9	129.7	11,743	11,413	+ 2.9
Florida	1.2	1.2	.....	1.2	106	105	+ 1.0
Illinois	216.5	210.8	+ 2.7	212.9	19,761	19,582	+ 0.9
Indiana	33.2	32.7	+ 1.5	33.8	3,020	2,931	+ 3.0
Kansas	289.3	339.8	— 14.9	310.5	27,705	30,168	— 8.2
Kentucky	60.0	68.6	— 12.5	63.1	5,663	5,901	— 4.0
Louisiana	1,087.7	909.5	+ 19.6	1,082.8	98,742	84,002	+ 17.5
North Louisiana	114.6	122.5	— 6.5	114.8	10,691	11,104	— 3.7
South Louisiana	973.1	787.0	+ 23.6	968.0	88,051	72,898	+ 20.8
Michigan	32.6	26.3	+ 24.0	30.0	2,908	2,309	+ 25.9
Mississippi	135.2	122.5	+ 10.4	145.1	13,050	10,862	+ 20.1
Mo.-So. Dak.-Tenn.	0.8	0.1	+700.0	0.8	59	7	+742.9
Montana	80.2	83.7	— 4.2	79.3	7,341	7,379	— 0.5
Nebraska	61.7	52.4	+ 17.7	63.2	5,734	5,051	+ 13.5
Nev.-Wash.-Alaska-Ariz.	0.9	0.2	+350.0	1.0	81	59	+ 37.3
New Mexico	303.9	289.7	+ 4.9	299.9	27,439	25,288	+ 8.5
Southeast New Mex.	268.8	253.5	+ 6.0	263.9	23,939	22,362	+ 7.1
Northwest New Mex.	35.1	36.2	— 3.0	36.0	3,500	2,926	+ 19.6
New York	5.0	5.1	— 2.0	4.9	445	490	— 9.2
North Dakota	52.4	51.6	+ 1.6	58.9	5,120	4,458	+ 14.8
Ohio	11.8	15.6	— 24.4	12.2	1,153	1,356	— 15.0
Oklahoma	537.3	562.9	— 4.6	560.6	50,252	50,529	— 0.6
Pennsylvania	15.2	16.1	— 5.6	16.0	1,443	1,433	+ 0.7
Texas	2,679.0	2,885.3	— 7.2	2,778.4	247,769	260,507	— 4.9
Dist. 1: South Central	44.5	45.8	— 2.8	44.5	4,005	4,055	— 1.2
Dist. 2: Middle Gulf	123.3	125.9	— 2.1	127.5	11,286	11,502	— 1.9
Dist. 3: Upper Gulf	364.3	407.6	— 10.6	390.2	34,335	37,376	— 8.1
Dist. 4: Lower Gulf	206.3	208.5	— 1.1	202.7	18,153	18,624	— 2.5
Dist. 5: East Central	29.4	32.3	— 9.0	27.7	12,564	2,874	+337.2
Dist. 6: Northeast	263.5	289.1	— 8.9	273.9	24,271	26,181	— 7.3
Dist. 7-B: North Central	137.4	145.1	— 5.3	138.9	12,486	19,285	— 35.3
Dist. 7-C: West Central	130.6	136.2	— 4.1	133.1	11,850	12,692	— 6.6
Dist. 8: West	1,076.0	1,134.9	— 5.2	1,136.2	99,898	102,300	— 2.4
Dist. 9: North	194.4	208.0	— 6.5	194.2	17,705	18,878	— 6.2
Dist. 10: Panhandle	109.3	107.9	+ 1.3	109.4	9,951	9,629	+ 3.3
Utah	107.7	111.5	— 3.4	107.4	9,874	9,827	+ 0.5
Virginia	.....	.....	.....	.....	1	2	— 50.0
West Virginia	6.0	5.8	+ 3.4	5.4	512	517	— 1.0
Wyoming	327.6	342.7	— 4.4	348.7	31,292	30,238	+ 3.5
Total, U.S.	7,103.6	7,188.4	— 1.2	7,275.4	655,337	648,200	+ 1.1

Sources for above 3 tables: Bureau of Mines monthly reports, except last two months based on API and B. of M. weekly reports and WORLD OIL estimates, and all Texas districts from API.

explain. Also, the drop in demand for residual fuel oil may have been caused in part by competition from gas and coal and limits on imports.

Supply. The industry has been at least partially successful in balancing supply with demand. But it probably would have been more successful if demand had not fallen below expectations. New supply in the first quarter was held almost 200,000 barrels a day or 2.6 percent below that in last year's initial quarter, compared with the decrease of 70,000 barrels or 0.7 percent in demand.

U. S. crude production was unchanged from last year at 7,202,000 barrels daily. But production of natural gas liquids was up 60,000 barrels daily or 6.8 percent. The principal curtailment of supply was in imports, which were cut 323,000 barrels daily or 14.6 percent. In the early months of 1959 they were abnormally high, as shipments were heavy just before mandatory controls on imports were started.

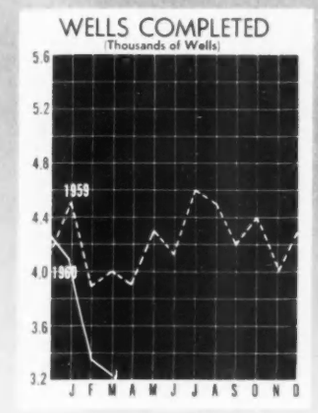
Crude runs to stills were reduced less effectively than new supply. At 8,080,000 barrels daily they were down 110,000 daily or 1.4 percent from last year's first three months.

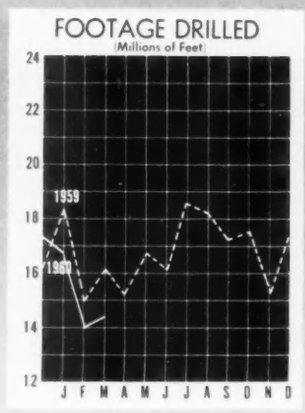
Stocks. The curtailment of new supply was sufficient to cause withdrawal of 532,000 barrels of oils from storage in this year's first quarter, or 194,000 more than the 338,000 daily withdrawn in the like period last year.

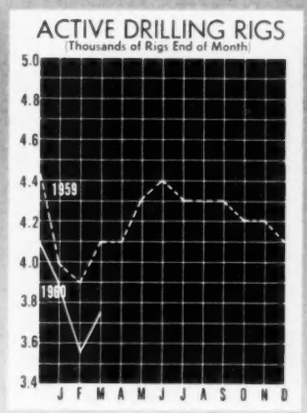
On March 31, 1960, stocks of all oils totaled 750.6 million barrels, down 8.5 million or 1.1 percent from one year earlier. Crude stocks of 258 million barrels were up about 3 million or 1.2 percent. Gasoline stocks of 225.6 million barrels were up 7 million or 3.2 percent. That increase is in line with predicted gains in gasoline demand in coming quarters. But doubt is cast on the forecasts by the first quarter decrease. Stocks of distillate, kerosine, and residual were lower at the end of March than one year before.

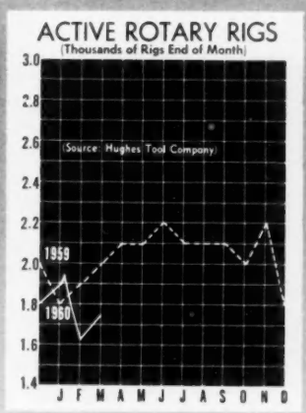
More scattered cuts in crude prices have disturbed the markets. But plans for continued strict proration of crude production offer hope that markets will stabilize.

Drilling Activities.









Rig activity increases in late March

LEAP YEAR 1956 was the biggest drilling year in oil industry history. Leap year 1960 is down 23 percent or more in every category from that peak year.

Following is this year's first quarter report, compared with the same 1956 period:

- **New well completions:** 10,464, down 3,826 wells or 26.8 percent.
- **Wildcats drilled:** 2,196, down 697 wells or 24.1 percent.
- **Footage drilled:** 45.2 million feet, down 13.6 million feet or 23.1 percent.
- **Rigs operating on March 31:** 3,760, down 1,123 rigs or 23 percent.

Severe winter weather continued to hamper March drilling activity. New well completions averaged 105 wells per day, down 9 wells daily or 7.9 percent from February, and 19 wells daily or 15.5 percent from the March 1959 average.

However, rig activity started to increase during the latter part of the month. The 3,760 rigs operating on March 31 reflected a 179-rig increase over the end of February, but the total still was 359 rigs less than the 4,119 operating on March 31, 1959.

Footage drilled dropped 18,250 feet per day during March to 464,510 feet daily, compared with 482,760 feet daily in February.

Summary of U. S. Drilling Activity

ITEM	March 1960	Feb. 1960	THREE MONTHS January-March 1960	1959	% Diff.
New Wells Completed:					
Oil	1,568	1,635	5,054	6,148	—17.8
Distillate	76	61	223	211	+ 5.7
Gas	249	328	935	908	+ 3.0
Service	73	49	156	203	—23.2
Dry	1,277	1,220	4,096	4,383	— 6.6
Total New Wells	**3,243**	**3,293**	**10,464**	**11,853**	**—11.7**
Footage Drilled (Millions of Feet)	**14.4**	**14.0**	**45.2**	**49.7**	**— 9.1**

Summary of U. S. Wildcat Drilling

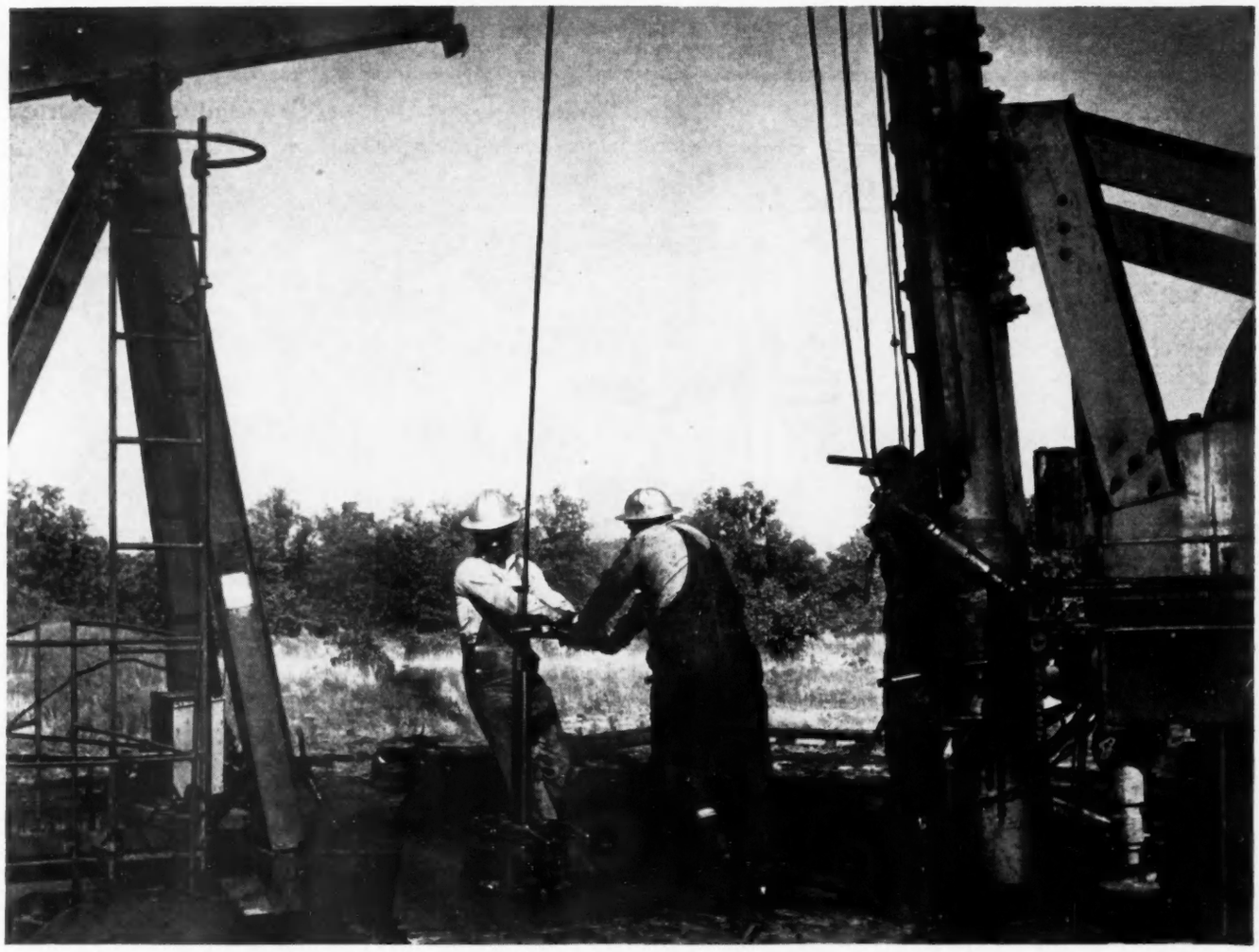
ITEM	March 1960	Feb. 1960	THREE MONTHS January-March 1960	1959	% Diff.
New Field Discoveries:					
Oil	36	32	132	166	—20.5
Distillate	10	6	24	27	—11.1
Gas	18	17	54	68	—20.6
Total Discoveries	**64**	**55**	**210**	**261**	**—19.6**
Dry Wildcats	**607**	**572**	**1,986**	**2,047**	**— 3.0**
Total Wildcats	**671**	**627**	**2,196**	**2,308**	**— 4.9**
(Percent Productive)	9.5	8.8	9.6	11.3	.....
(Percent Dry)	90.5	91.2	90.4	88.7	.....

U.S. Drilling Activity in March and First 3 Months, 1960-1959

STATE or DISTRICT	TOTAL NEW WELLS COMPLETED AND FOOTAGE DRILLED: DETAILS FOR MARCH, 1960 — Oil	Dist.	Gas	Dry	Service Wells	TOTAL NEW WELLS — Mar. 1960	Feb. 1960	Mar. 1959	Total Footage March 1960	DETAILS FOR JANUARY-MARCH: NEW WELLS — 1960	1959	Percent Diff.	FOOTAGE — 1960	1959
Alabama	2			1		3	4	10	26,603	14	30	— 53.3	120,493	295,327
Alaska	2					2		1	23,088	3	2	+ 50.0	34,288	26,420
Arizona				1		1	1		520	3	1	+200.0	7,700	2,000
Arkansas	11	1	1	19		32	51	57	143,748	133	204	— 34.8	485,825	670,229
California	58		4	31	1	94	95	105	458,954	311	350	— 11.2	1,410,062	1,736,962
Colorado	9		5	31		45	57	58	241,094	192	166	+ 15.7	1,040,391	880,431
Illinois	42			62		104	128	87	207,483	472	454	+ 4.0	941,001	1,019,941
Indiana	10			29		39	60	39	48,348	179	171	+ 4.7	226,543	285,807
Kansas	73		3	110	2	188	252	322	687,967	774	892	— 13.2	2,805,432	3,230,673
Kentucky	122		20	70		212	238	167	171,272	685	616	+ 11.2	575,150	568,501
Louisiana	109	14	26	107		256	237	253	2,166,884	736	912	— 19.3	6,201,791	7,218,420
North Louisiana	37		11	31		79	63	88	338,614	212	318	— 33.3	829,469	1,173,975
South Louisiana	72	14	15	76		177	174	165	1,828,270	524	594	— 11.8	5,372,322	6,044,445
* Offshore	24	3	4	21		52	47	38	532,553	138	126	+ 9.5	1,418,627	1,253,735
Michigan	35			25	3	63	64	45	214,648	186	130	+ 43.1	645,411	376,361
Mississippi	39	2	2	32		75	60	52	761,828	200	152	+ 31.6	1,911,392	1,417,752
Missouri										2	2		6,800	1,364
Montana	9			10		19	22	20	94,302	60	77	— 22.1	262,486	347,511
Nebraska	20			39		59	61	64	346,961	246	159	+ 54.7	1,452,369	921,320
New Mexico	86		20	31	1	138	142	137	729,066	459	390	+ 17.7	2,213,603	1,635,019
Southeast	72		2	28	1	103	90	85	571,505	303	216	+ 40.3	1,525,170	1,064,796
Northwest	14		18	3		35	52	52	157,561	156	174	— 10.4	688,433	570,223
New York	12		1	3	7	23	24	23	38,490	72	67	+ 7.5	124,205	114,365
North Dakota	20			5		25	25	31	160,064	77	103	— 25.3	479,380	646,400
Ohio	36		18	37		91	87	76	214,683	265	216	+ 22.7	663,715	581,322
Oklahoma	165	7	30	111	39	352	285	584	1,433,170	1,015	1,676	— 39.4	4,346,116	5,628,644
Pennsylvania	18		25	15	12	70	60	49	222,468	195	140	+ 39.3	575,905	460,276
South Dakota	2					2	5	2	16,945	12	5	+140.0	89,149	14,161
Tennessee				5		5	4	10	3,750	17	30	— 43.3	12,972	30,000
Texas	640	52	48	455	7	1,202	1,152	1,491	5,340,719	3,676	4,454	— 17.5	16,602,052	19,681,856
Dist. 1: South Central	43	1	2	27		73	81	110	206,586	243	268	— 9.3	694,630	677,185
Dist. 2: Middle Gulf	14	13	11	27		65	54	63	445,961	182	178	+ 2.2	1,216,142	1,098,393
Dist. 3: Upper Gulf	37	17	3	29		86	89	73	639,179	281	266	+ 5.6	2,056,934	1,937,947
*Gulf of Mexico														
Dist. 4: Lower Gulf-S.W.	19	19	5	50		93	74	106	543,016	253	310	— 18.4	1,453,710	1,763,942
*Gulf of Mexico														
Dist. 5: East Central	2	2	2	6		12	11	10	83,654	52	34	+ 52.9	262,781	198,658
Dist. 6: Northeast	31		1	14		46	58	62	278,058	189	193	— 2.1	1,028,958	1,075,357
Dist. 7-B: North Central	81		6	99		186	174	221	566,554	537	624	— 14.0	1,714,658	1,989,027
Dist. 7-C: West Central	34		2	29		65	57	57	260,528	182	168	+ 8.3	779,183	733,442
Dist. 8: West	201		2	63	7	273	238	413	1,394,367	816	1,208	— 35.7	4,291,071	6,347,460
Dist. 9: North	133		5	84		222	224	292	587,331	650	855	— 24.0	1,823,781	2,445,829
Dist. 10: Panhandle	45		9	27		81	92	84	335,485	291	290	+ 0.3	1,280,204	1,414,616
Utah	9			12		21	23	28	109,665	56	83	— 32.5	304,952	489,731
Washington							1			1			8,520	
West Virginia	5		40	11		56	70	71	129,718	194	188	+ 3.2	479,827	493,709
Wyoming	34		5	25	1	65	83	52	351,050	224	181	+ 23.8	1,096,954	946,253
Others			1			1	2		7,524	5	2	+150.0	30,131	5,738
Total United States	1,568	76	249	1,277	73	3,243	3,293	3,834	14,351,012	10,464	11,853	— 11.7	45,154,615	49,726,493
Total Western Canada	122		24	91		237	215	268	1,185,000	694	667	+ 4.0	3,746,647	3,501,540

STATE or DISTRICT	WILDCAT DRILLING IN MARCH AND FIRST THREE MONTHS, 1960-1959: DETAILS FOR MARCH, 1960 — Oil	Dist.	Gas	Dry	Total Wildcats	DETAILS FOR JANUARY-MARCH — Oil	Dist.	Gas	Dry	TOTAL WILDCATS — 1960	1959	DRILLING RIGS IN OPERATION (Rigging up, Drilling, Temp. Shut-down) — Mar. 31 1960	Feb. 29, 1960	Mar. 31, 1959
Alabama									2	2	6	5	4	12
Alaska									1	2	2	5	5	4
Arizona									3	3	1	7	4	1
Arkansas				1	1				27	28	27	48	25	43
California		1		6	7		1		61	66	64	121	102	143
Colorado	1			19	20	3		2	83	91	93	104	56	64
Illinois				17	17	6		2	156	160	108	236	253	214
Indiana	1			35	36	4			77	78	43	130	129	69
Kansas				20	20	1			197	225	255	232	227	269
Kentucky	7		2	66	75	24		4	12	14	25	84	111	140
Louisiana	2			36	38	6	2	2	97	107	114	351	327	365
North Louisiana	2			11	13	2		1	29	32	33	67	52	55
South Louisiana				25	25	4	2	1	68	75	81	284	275	310
* Offshore				3	3				9	9	11	59	49	52
Michigan				15	15	2			52	54	40	114	109	85
Mississippi	2			19	21	5			64	69	54	72	78	81
Missouri											1	1	1	
Montana				7	8	3		2	18	23	30	28	25	41
Nebraska	1			20	21	6			93	99	74	44	36	33
New Mexico	2		4	20	26	12		8	71	91	53	132	111	183
Southeast	2		1	17	20	8		3	56	67	38	90	79	90
Northwest			3	3	6	4		5	15	24	15	42	32	93
New York												25	25	25
North Dakota												16	17	51
Ohio	1			1	2	1			9	10	23	174	178	199
Oklahoma			1	1	2	2		1	7	10	4	402	395	442
Pennsylvania	3		5	20	28	11	2	10	90	113	233	210	180	180
South Dakota				3	3			1	5	6	4	2	1	2
Tennessee									4	4	4	20	20	25
Texas	10	9	4	270	293	39	18	18	744	819	951	884	834	1,089
Dist. 1: South Central				21	21				71	71	74	36	32	34
Dist. 2: Middle Gulf	1	2	1	16	20	1	5	3	45	54	65	47	51	64
Dist. 3: Upper Gulf	1	3		16	20	3	6		60	69	64	90	89	88
*Gulf of Mexico												1	1	1
Dist. 4: Lower Gulf-S.W.		4		35	39	3	7	6	79	95	97	81	66	90
*Gulf of Mexico														
Dist. 5: East Central														
Dist. 6: Northeast			1	5	6	1		2	29	32	15	11	10	10
Dist. 7-B: North Central			1	7	8	2		1	33	36	43	71	32	50
Dist. 7-C: West Central				69	72	12		4	166	182	202	86	100	110
Dist. 8: West	1			19	20	3		1	49	53	52	74	72	72
Dist. 9: North	4		1	39	44	11		1	90	102	163	157	186	334
Dist. 10: Panhandle				32	32	3			94	97	131	144	113	142
				11	11				28	28	45	87	83	95
Utah				4	4	1		1	22	24	25	38	39	45
Washington									1	1				
West Virginia												168	210	213
Wyoming												103	75	86
Others									5	5	2	4	4	15
Total United States	36	10	18	607	671	132	24	54	1,986	2,196	2,308	3,760	3,581	4,119
Total Western Canada												185	256	214

* Gulf of Mexico wells are included in their respective district totals.



Nickel alloy steel sucker rods kept this crew from going fishing

When a subsurface pump jammed, this crew had a pulling job to do. But that was all! No costly, time-consuming fishing was needed.

Why not? A simple but important reason: because the sucker rods were made of nickel steel, they were able to take the wrench of jamming without parting . . . *even though they were already carrying a heavy load.*

When pumping deep wells at excessive loads, nickel alloy steel sucker rods have demonstrated outstanding strength along with high fatigue resistance. When pumping corrosive wells, they have demonstrated, as well, a resistance to corrosion and corrosion-fatigue that adds many valuable pumping hours before replacement is necessary.

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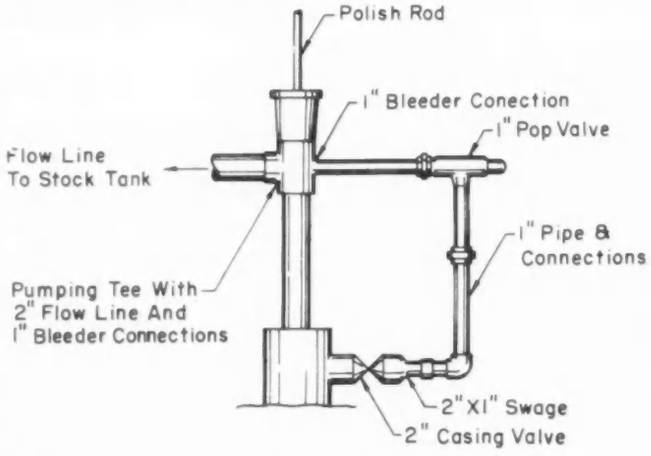
Practical Operating Hints

These **How-To-Do-It** Ideas Can Save You Money

$10 is paid for each illustrated acceptable contribution. Mail to The Editor, WORLD OIL, P. O. Box 2608, Houston 1, Texas

Pop Valve on Flow Line for Safety

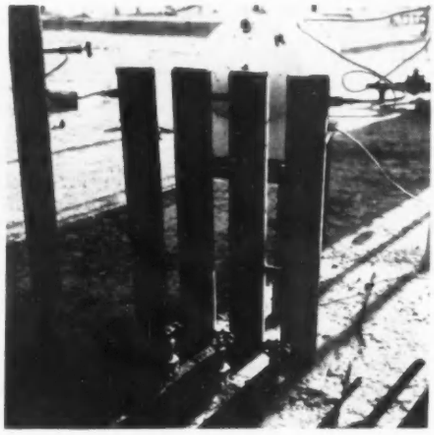
One operator has installed a 1-inch pop valve on his pumping wellheads to protect the tubing string and flow line from damage when lines become plugged with gyp, paraffin or for any other reason. Previously, split tubing and/or flow lines resulted when an unattended well continued to pump against a plugged line.



The 1-inch pop valve is installed on the 1-inch bleeder connection of the pumping tee and is tied into the 2-inch casing valve. A minimum number of 1-inch connections are required. When lines become plugged and flow line pressure rises, the pop valve opens at a preset release pressure and allows production to be popped over into the casing annulus. The well will continue to pump "through itself" without damage until the trouble is corrected.

Keep Rig Area Neat With Surplus Parts Storage Bin

This storage bin is constructed using 1-inch angle irons welded together to form a framework 4 feet by 5 feet by 8 feet. A heavy mesh wire is then welded to the angle iron and the storage bin is completed. One end is hinged so that the component spare parts may be removed.

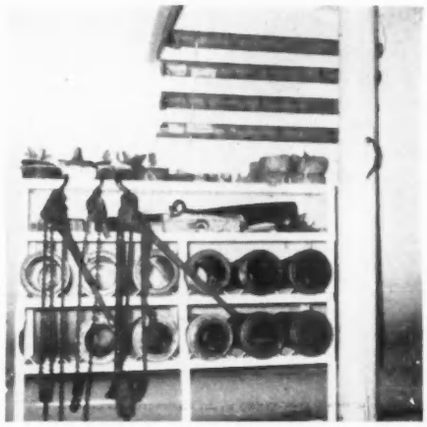


Quadruple Scrubber Yields Dry Supply Gas

This four-barrel drip does an excellent job of providing liquid free supply gas to pneumatic operated controls on this tank battery. Copper tubing is used to tie the scrubber into the separator gas line shown at far left.

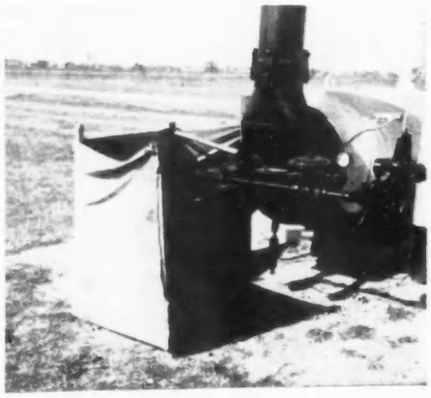
As wet gas enters the scrubber, it must travel to the bottom of the first barrel, pass through a ½-inch nipple to the second, travel to the top of the second barrel and then pass through another ½-inch nipple to the third barrel.

The procedure is repeated in this fashion until ready-to-use dry supply gas is discharged at the top of the fourth scrubber barrel on the right. All barrels are made of 4-inch line pipe and can be field constructed with a minimum of welding time required.



Store Pump Liners and Rod Holders on a Rack

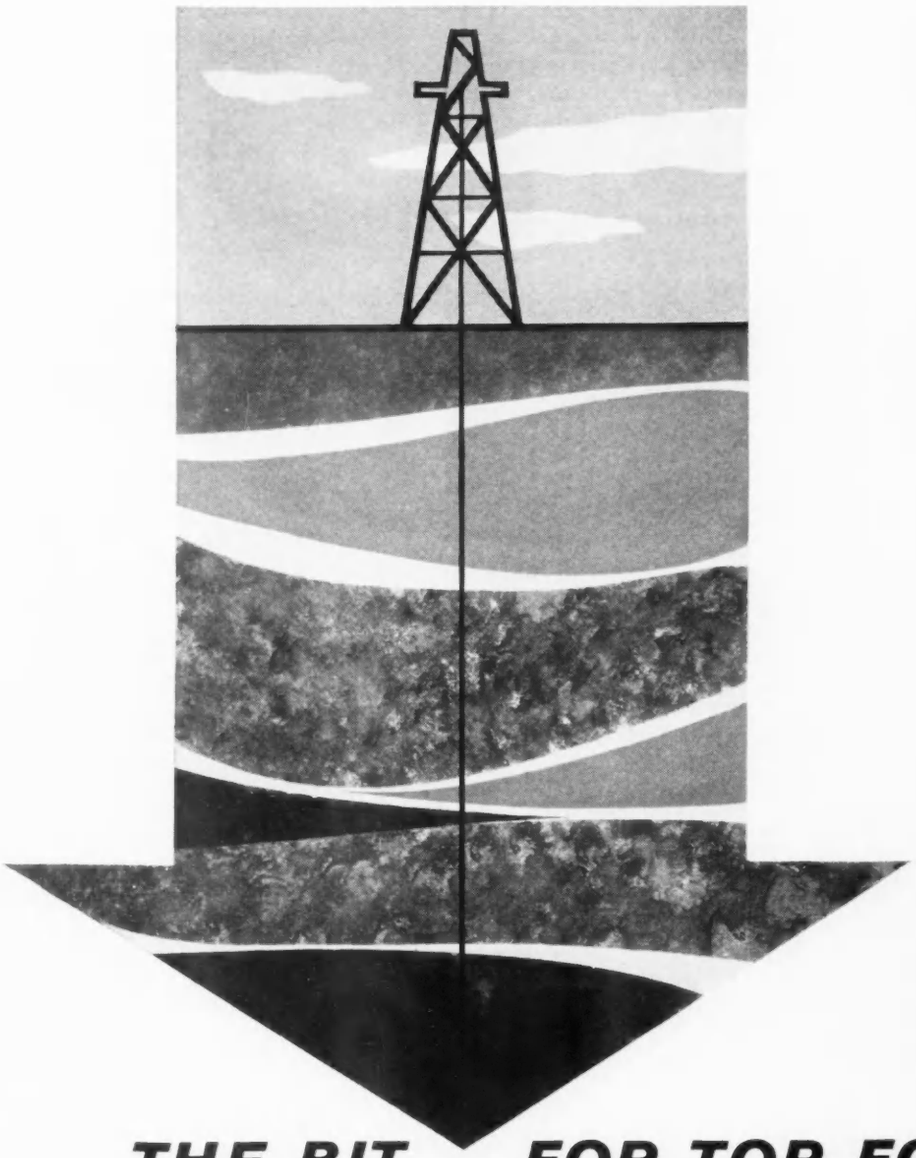
Protect costly slush pump parts by storing them on a simple rack. Cut 1-inch angle to form the rack. Weld a heavy mesh wire to the frame, forming a suitable place to store unused liners, valves and seats. The liners are stored on brackets that are cut and welded on the wall of the parts house. Cut the brackets to prevent the liners from rolling onto the floor.



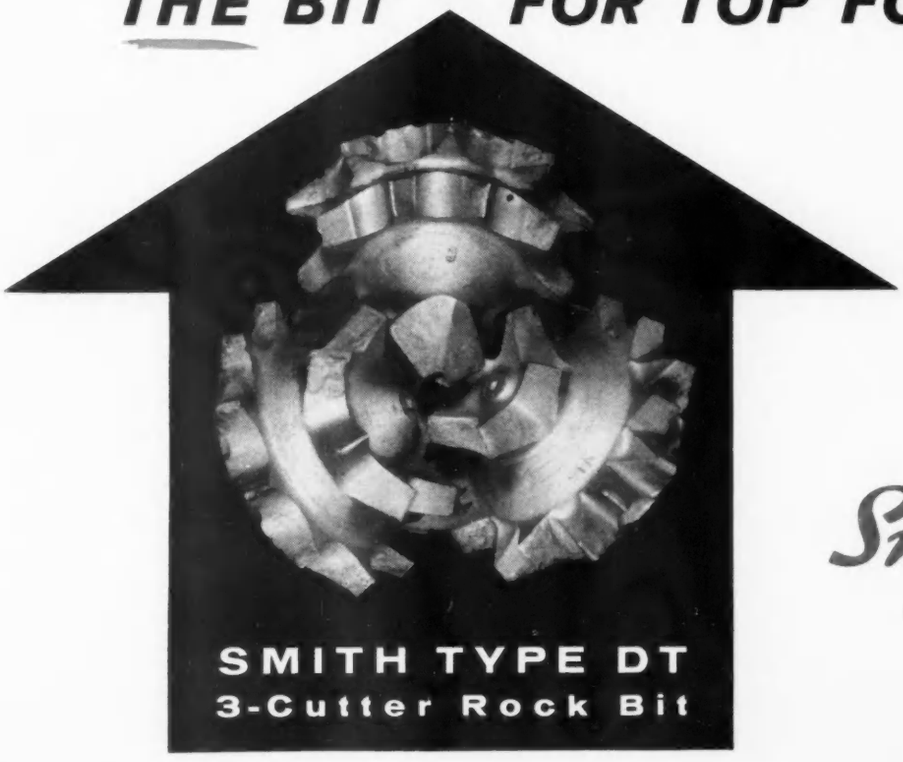
Make Canvas Windbreak For Heater Fire Box

A strip of discarded canvas or an old tarpaulin strung on vertical support can be used to construct a simple line heater wind break. Before installing the windbreak there was considerable difficulty involved in keeping the heater lighted because of strong winds.

Four short wooden stakes were driven into the ground on the windward side of the heater and an old discarded tarpaulin was installed.



THE BIT FOR TOP FORMATIONS



The **SMITH TYPE DT** 3-cutter rock bit is designed and constructed to insure rapid rates of penetration in moderately soft to soft formations . . . sturdy, deeply cut and widely-spaced teeth . . . optimum self-cleaning properties is provided by the widely-spaced teeth in combination with ample tooth deletions and efficient flushing action of the circulating fluid.

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Make Rig Light Support With Pieces of 2-Inch Pipe

This rig-light support can be made from a long and short piece of 2-inch pipe. The shorter of the two is welded at right angles to the longer one. The long piece of pipe forms the support for the shorter length through which the electric light wire is strung.

In this case, the long support pole is welded to the corner of the mud tank; however, where good lighting is necessary, this lighting arrangement may be used.

Use Discarded Drum For Oil Receptacle

This West Texas operator has installed a discarded 55-gallon chemical drum in a horizontal position adjacent to the fire wall pump to serve as a sump. A small rectangular hole is cut in the top (or side) of the drum as indicated. The pump bleed, which is used to determine if the pump is actually pumping, is connected to the drum by a length of copper tubing which passes through the hole.

The 2-inch bung in the top (or side of the drum as shown here) is removed and the drum is manifolded to the pump suction. When the bleed is used, oil or water is discharged into the drum. When the drum is filled, the suction lines are switched and the drum is pumped out to the treater. The installation improves the appearance of the battery and prevents pollution.

Steel Rack Keeps Subs Convenient, Speeds Moves

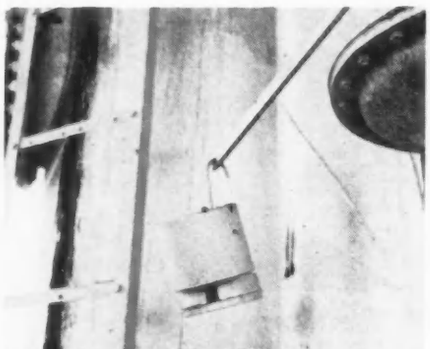
This compact storage rack keeps subs convenient and speeds up moves. The entire rack of subs can be loaded on a truck and moved quickly. The rectangular rack is made up of 24 pieces of salvaged casing, all welded together where they contact each other and welded in turn to the 3/4-inch base plate. At each corner is welded a heavy lifting ear to which slings easily can be attached. Whenever a special problem or fishing job arises requiring various subs, this rack can be rushed to the well with the knowledge that nearly every combination that might be necessary is included in the selection.

Install Water-Tight Cover For Gasoline Lease Pump

Here is an easily constructed cover which is used to protect gasoline powered centrifugal lease pumps from weather and damage from livestock. This installation has been set up on a concrete base. The galvanized cover has been constructed over a lightweight wood frame which in turn has been built to conform to the concrete foundation. The weight of the cover holds it in place and provides watertight protection for the pump installation. The cover is made quickly and easily in the field at minimum cost.

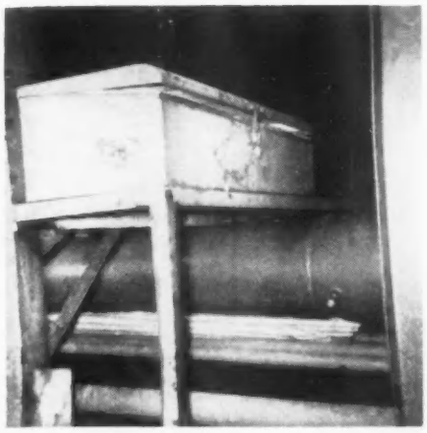
Metal Support Prevents Air Line From Burning

Bolt a metal bracket to the engine mount to support air lines. This will prevent air lines from being burned by exhaust or manifold. Then weld a short piece of small diameter pipe to this bracket. The air line to the diesel engine then is passed through this support.



Discarded Tubing Collars Used as Counterweights

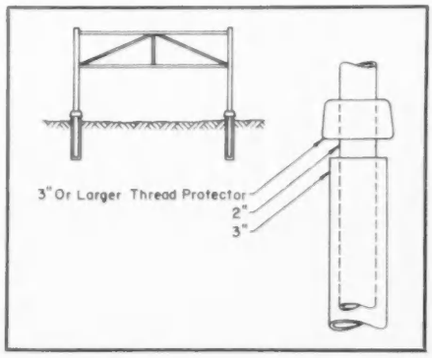
Old discarded line pipe or tubing collars can be used to supplement the weights normally used to counterbalance the treater water leg diaphragm discharge valve. A 4-inch collar has been used to provide additional weight in this case.



Keep Tools Convenient With a Built-In Chest

This tool chest is built into the rig superstructure so tools can be conveniently stored.

The base of the tool chest is made of 2-inch angle iron. The tool box rests on a piece of flat ¼-inch plate-iron. The tool box can be welded to the bottom plate or merely set in place.



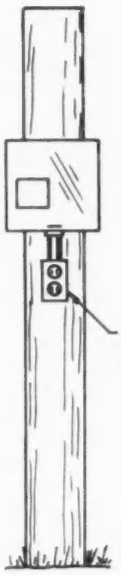
Build Movable Fence With Pipe and Thread Protectors

Build a protective fence that is easily moved or replaced with 3-inch pipe, 2-inch pipe and thread protectors. To erect the posts, bury a length of 3-inch pipe with a few inches projecting above the ground level. One section of 2-inch pipe is used for each fence leg. Three-inch or larger thread protectors are welded bell down to the 2-inch fence legs. The thread protectors bear down upon the buried 3-inch pipe and support the fence.

The protectors will prevent dust or sand from blowing into the 3-inch pipe receptacle. If the fence is to be installed on a level location, the tops of the 3-inch should have the same elevation and the thread protectors should be positioned the same distance from the top of each fence leg.

Outlet on Power Pole Provides Extra Light

For a very small additional cost when wiring a well location, a 110 or 220-volt utility outlet can be wired onto the motor control power pole. This makes lighting the location for future workovers or pulling jobs very convenient. It also enables engineers or production men to have lights at the well if they are running production tests around the clock.



At various times, different power tools, spray guns or electric drills, can be used at the location, thus improving efficiency of the roustabout crew or pumper personnel.

Patent Pending

No-Wall-Stick Drill Collars

effectively reduce sticking of drill collars. . .

Please write Houston office for descriptive brochure and price schedules

No-Wall-Stick Drill Collars

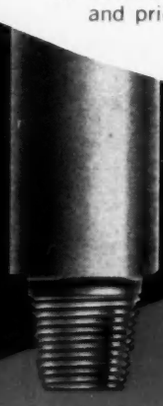
The surface area of these drill collars has been changed to reduce wall contact area by more than 40%. Weight loss of the drill collar is only about 4%. Reduction of 40% in contact area results in a proportionate decrease in the total sticking force due to differential pressure of 40%. This design also gives a section of pressure equalization each foot along the body of the drill collar.

Three sizes (6", 4¾", 4⅛") of NO-WALL-STICK DRILL COLLARS are available on a rental basis in the Texas and Louisiana Gulf Coast area. Rental price of these NO-WALL-STICK DRILL COLLARS is very competitive to conventional drill collars run with stabilizers.

Any new or used drill collars, regardless of size, owned by Drilling Contractors or Oil Companies may be converted to NO-WALL-STICK DRILL COLLARS for a fixed conversion charge.

NO-WALL-STICK DRILL COLLARS offer far more protection from wall sticking in high angle holes or holes which have shale wash outs than drill collar strings using stabilizers.

NO-WALL-STICK DRILL COLLARS will not ball up, will not peel off wall cake, and may be sealed off by a Hydril type blow out preventor at any point.



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AN API FEATURE

WORLD OIL BRINGS FOUR API MEETINGS TO YOU

Looking for new cost cutting ideas? The latest reports on new equipment and methods? Or a better way to determine costs?

These are just a few of the subjects covered in four spring meetings of the American Petroleum Institute's Production Division, held during March and April.

On the following pages are feature articles based on eight outstanding papers presented at the sessions. So that you may have the complete picture, this special API Section also includes abstracts of 21 papers, and the listing of 26 more.

SLIM HOLE COMPLETIONS CUT DEVELOPMENT COSTS

Hudson's Bay Oil and Gas Company, Ltd. has completed 36 small diameter cased wells in Canada at a savings of 35 percent compared to conventional completions

By James G. Bonsall, Production Engineer
Hudson's Bay Oil and Gas Company, Limited
Edmonton, Alta.

Hudson's Bay Oil and Gas Company Limited has completed 36 wells in Canada using the slim hole technique. This technique has been modified and applied to three dual-zone "associated completions." The experience to date with these slim holes has led to the following conclusions:

- The slim hole completion technique, in which 2⅞-inch tubing is cemented in 6¼-inch hole, has been proved mechanically sound and no more than average difficulties might be expected.
- Slim hole wells can be produced in a conventional manner with pumping, intermitter and plunger-lift installations.
- Actual cost data have proved that Hudson's Bay has enjoyed cost savings averaging 35 percent compared to conventional methods. Theoretically, operators comparing slim holes to conventional holes should expect a cost savings of 28 percent.
- The slim hole technique can be further modified for "associated" dual-zone completions. This method, wherein 2 strings of 2⅞-inch tubing are cemented in the same bore hole, saves 18 percent over a conventional dual zone completion and has a further advantage of positive segregation.

As the boundaries of the Pembina field extended, Hudson's Bay Oil and Gas Company Limited became bur-

AN API FEATURE

Slim Hole Completions

dened with fringe leases whose marginal reserves were rendered uneconomical through the use of conventional completion methods. To investigate other avenues, a 2-well experimental program was launched in the fall of 1956. The purpose was to evaluate the feasibility of slim hole drilling and completion. The experimental program entailed cementing 2⅞-inch tubing in 6¼-inch hole.

The results of these two experimental wells were sufficiently rewarding that a technique evolved for the drilling and completion of all future wells in Pembina field. The technique has also been applied in other fields where water or free gas is not a problem. Thirty-six wells have been completed to date using the slim hole technique, with depths varying from 2,600 feet to 6,900 feet.

Experience to date has proved that no particular saving can be realized in the drilling phase. At the time locations came up, rigs equipped for slim hole work were not readily available and contractors were bidding equivalent rates for slim holes and conventional holes. Therefore, consideration of the drilling phase has been omitted from this article with discussion confined to completion technique, producing practices and some related experiences.

A further modification of the slim hole technique has been applied in dual zone completions. This type completion has been classified as an "associated completion" and incorporates two strings of 2⅞-inch tubing cemented in the same bore hole. At this time, three wells have been completed in this manner; and not only are cost savings realized, but there is a definite operational advantage over conventional dual zone completions.

Well program. A typical well program for a slim hole completion in the Cardium sand is as follows (Figure 1):

1. Drill sufficient 9⅞-inch hole to set 450 feet of 7-inch surface casing.
2. Drill 6¼-inch hole to the top of the Cardium sand.
3. Cut a 50-foot diamond core with 5½-inch bit.
4. Ream the rat hole with 6¼-inch bit and deepen the hole to the required depth, i.e., sufficient hole to permit setting the float shoe approximately 50 feet below the anticipated bottom perforation.
5. Run the production string of 2⅞-inch tubing with a 4½-inch float shoe, 4½-inch x 2⅞-inch swage, 10-foot pup joint, and 2-foot bar joint from the bottom up. Install a full open friction-type pump seating nipple in the string approximately 100 feet above the pay.

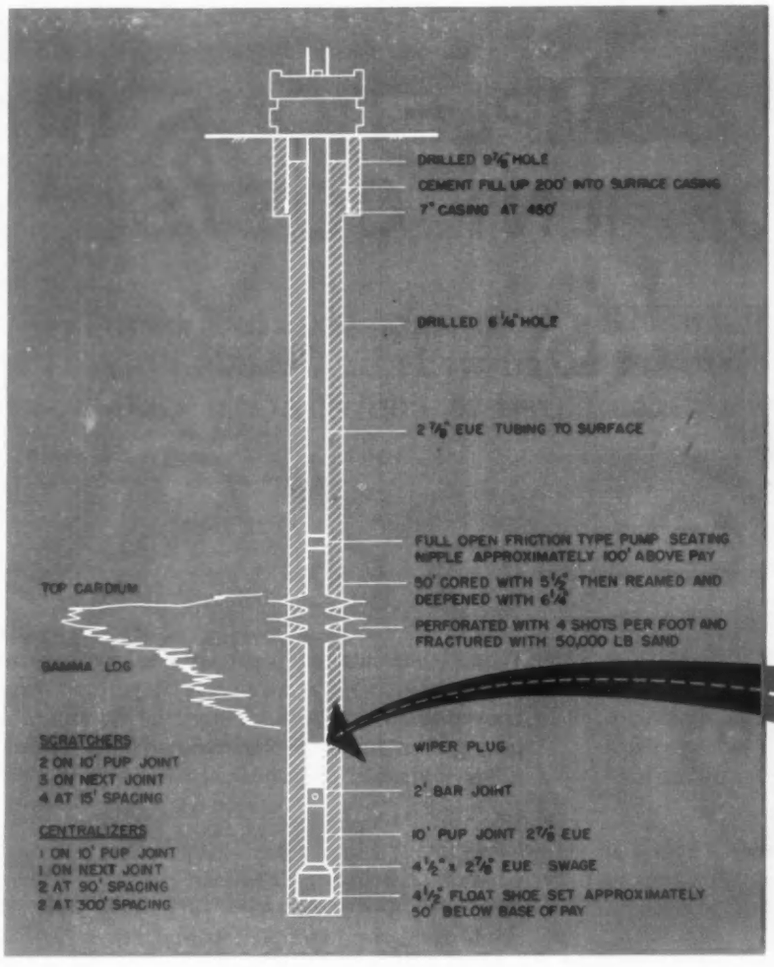

DRILLED 9⅞" HOLE
CEMENT FILL UP 200' INTO SURFACE CASING
7" CASING AT 450'
DRILLED 6¼" HOLE
2⅞" EUE TUBING TO SURFACE
FULL OPEN FRICTION TYPE PUMP SEATING NIPPLE APPROXIMATELY 100' ABOVE PAY
50' CORED WITH 5½" THEN REAMED AND DEEPENED WITH 6¼"
PERFORATED WITH 4 SHOTS PER FOOT AND FRACTURED WITH 50,000 LB SAND
TOP CARDIUM
GAMMA LOG
SCRATCHERS
2 ON 10' PUP JOINT
3 ON NEXT JOINT
4 AT 15' SPACING
CENTRALIZERS
1 ON 10' PUP JOINT
1 ON NEXT JOINT
2 AT 90' SPACING
2 AT 300' SPACING
WIPER PLUG
2' BAR JOINT
10' PUP JOINT 2⅞ EUE
4½" x 2⅞" EUE SWAGE
4½" FLOAT SHOE SET APPROXIMATELY 50' BELOW BASE OF PAY

FIGURE 1—Typical slim hole completion used by Hudson's Bay Oil and Gas Company, Ltd., in Canada.

FIGURE 2—Wiper plug used for cement displacement in slim hole completions.

6. Cement with sufficient volume to bring the cement top 200 feet into the surface casing, displacing the wiper plug with one barrel of oil, 250 gallons of acid and the remainder oil.

7. After 6 hours WOC, bleed off pressure and head up.

8. Release rig.

9. Run gamma ray-neutron log and, after a minimum 24 hours WOC, perforate the selected interval with 4 shots per foot.

10. Squeeze the acid into the formation and after a minimum of 3 hours reaction time, fracture the formation with the designed volume.

For wells completed in a formation not requiring fracturing, the wiper plug is displaced with oil only.

Production string design. The design of the production string from the bottom upward is as follows (Figure 1):

1. One 4½-inch float shoe
2. One 4½ x 2⅞ EUE swage
3. One 10-foot pup joint 2⅞ EUE
4. One 2-foot pup joint 2⅞ EUE with internal ½-inch steel cross bars welded securely
5. 2⅞-inch J-55, 6.5-lb per foot EUE tubing to surface.

One centralizer and two scratchers are placed on the 10-foot pup joint. One centralizer and 3 scratchers are placed on the first full joint of tubing, then 4 scratchers are placed at 15-foot spacing and 2 centralizers at 90-foot spacing. Two more centralizers are placed at 300-foot spacing.

A 4½-inch float shoe is preferred over a 2⅞-inch float shoe for several reasons. First, the 4½-inch shoe has more port area for circulating, and second, the 4½-inch float shoe provides a better centralizing effect. The 4½-inch shoe and swage are approximately the same price as a 2⅞-inch shoe.

The cross bars welded in the 2-foot pup joint provide a positive seat on which to bump the wiper plug. Laboratory tests proved that, at pressures up to 4,000 psi, the plug did not knock out the bars or deform sufficiently to leak.

A full open friction-type pump seating nipple is installed in the string approximately 100 feet above the pay. On the first wells pump seating nipples were not installed for fear of providing too much restriction for the wiper plug. However, laboratory tests have proved that little additional pressure is required to pass a plug through a full open seating nipple.

Cementing. It will be noted on Figure 1 that cementing specifications call for fill-up into the surface casing. To accomplish this a light-weight, high-yield cement is used for the largest portion, followed by a smaller volume of high-strength cement opposite the pay. The additional cost of bringing the cement above the required top into the surface pipe is well justified to provide rigid support and protection against external corrosion.

Cement is displaced with a wiper plug of special design (Figure 2). On several of the first slim holes, minor obstructions were encountered in the tubing when attempting to run logging tools. These obstructions, believed to be cement stringers caused by a poor wiping action, were easily removed by spudding with a sinker bar. However, they were a potential hazard so the service companies were presented with a suggested design for an improved wiper plug. The result was the wiper plug shown. Since its exclusive use, obstructions have no longer been encountered.

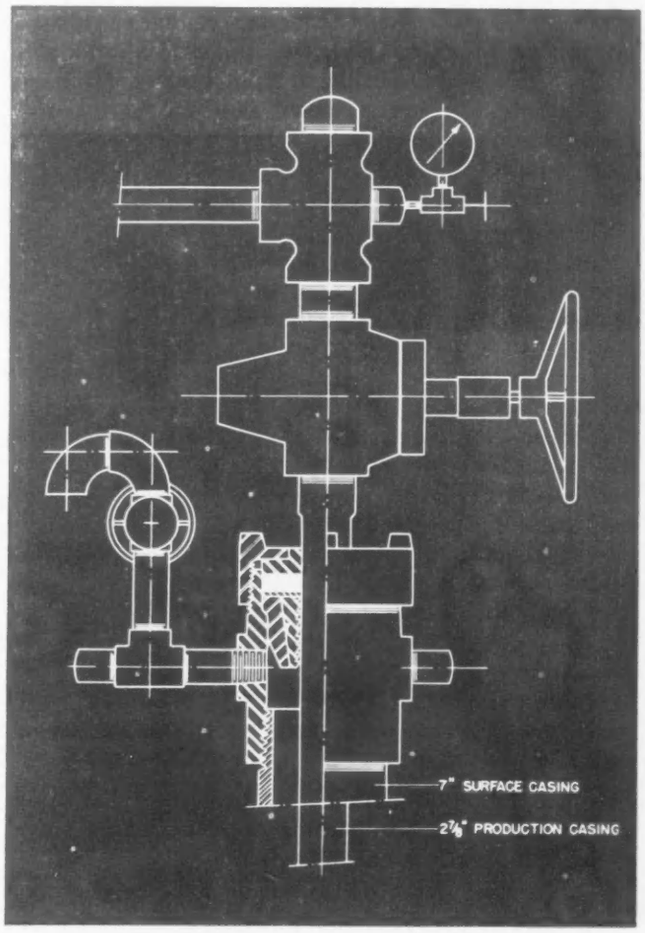


FIGURE 3—Wellhead for slim hole completions.

If the wiper plug were displaced in the normal manner with mud, a trip in the hole with a macaroni string would be necessary to displace the pipe and spot oil and acid on bottom for fracturing. To overcome the expense of this additional operation, oil and acid are used to displace the plug. As noted in the well program, one barrel of oil, then 250 gallons of acid precede the oil used to displace the plug. The one barrel of oil ahead of the acid simply provides an oil film on the pipe and aids the inhibitor in preventing acid attack on the pipe.

Immediately after the wiper plug is bumped, the pressure is bled off to test the float equipment. If the float is holding, 200 psi are held on the plug for 6 hours before bleeding off and landing the pipe. If the float is not functioning, a pressure equivalent to the differential between the two columns of fluid is left on the pipe for 6 hours. The float equipment is again tested to ensure no bleed back before heading up.

Wellhead. Wellheads used for the slim hole completions are compact and simple, as shown in Figure 3. Landing

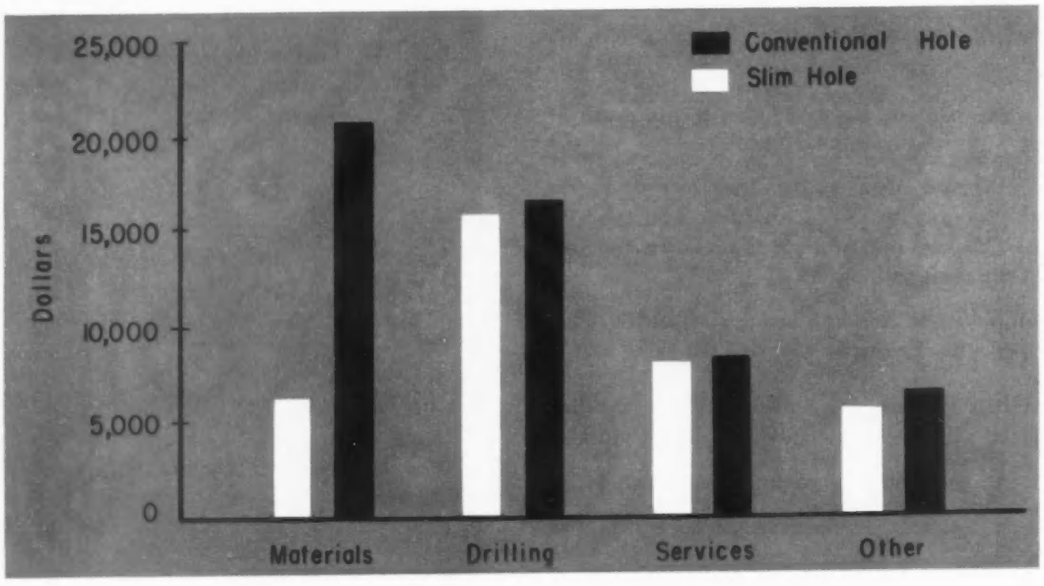


FIGURE 4—Cost breakdown—slim hole vs. conventional completion.

the tubing "proud" eliminates the necessity of using a high working pressure housing since the master valve is connected directly to the tubing string.

The landing depth of the tubing must be determined accurately so the slips may be readily positioned without leaving an excessive lenth of tubing protruding above the wellhead. If, however, either extreme arises, too much tubing protruding because of hole sloughing or not enough because of mis-measurement, the remedy is quite simple. In the former, the excess tubing is cut off and re-threaded with non-upset threads; in the latter, a ring is cut out of the surface casing to lower the tubing head housing.

Logging and perforating. As mentioned earlier, minor obstructions were encountered in several of the earlier slim holes when attempting to run logging tools to bottom. These obstructions were believed to be cement stringers caused by poor wiping during the cementing operations.

In every instance spudding with a sinker bar removed the obstructions sufficiently to permit the passage of logging tools and perforating guns. Since utilizing the redesigned wiper plug, obstructions have not been encountered.

Laboratory tests were conducted to determine if acid in the hole would have any detrimental effect on the perforating equipment. The tests showed no damage should occur in a reasonable length of time. On one well, collar-locator trouble necessitated pulling a gun that had been in the hole approximately 1 hour. The aluminum cotter pins locking the charges together were completely eaten away; however, there was no evidence of acid attack on the cast-aluminum charge bodies. Guns pulled out because of misfires after being in the hole shorter periods of time were completely intact.

Junk bridges opposite the perforations after shooting have been a common occurrence. In some instances it was impossible to drive the junk to bottom with sinker bars. This caused some concern since it could be hazardous to the fracturing operation. This concern was relieved considerably when it was found that these junk bridges disappeared after squeezing the acid away. Junk-free guns are now available which, of course, eliminate the problem completely.

Fracturing. In areas where slim hole completions have been utilized most extensively, it is necessary to stimulate the producing formation with a fracturing treatment. Pre-treatment with acid has proved very effective in reducing breakdown pressures and feeding pressures. To position the acid at the bottom of the hole, it is used as part of the displacement fluid following the cement wiper plug.

The pump truck is called out to the lease some 3 to 4 hours ahead of the other fracturing equipment to squeeze the acid into the formation. The acid reacts while all the equipment arrives and prepares for the operation.

The controversial requirement of a high feed rate cannot be achieved in small diameter casing completions. Attempts to obtain feed rates greater than 10 bpm have simply resulted in excessive pressures with little increase in feed rate. Therefore, a pump truck of the 600 to 900 hydraulic horsepower range is sufficient.

The fracturing fluid is treated with a fluid loss reducing agent to induce fracture extension. Gelling the fluid is not necessary to reduce sand falling rate because of the high-velocity pumping at eight bpm in tubing. In event of a sand-off, backwashing is not possible so temporary sand suspension is of no value.

The average fracture treatment consists of 50,000 lb of sand carried in crude oil treated with a fluid loss reducing agent. Concentrations average two ppg sand feeding eight bpm at 3,200 psi. Re-fracturing treatments have been performed successfully on several wells. One well in particular was fractured initially with 40,000 pounds of sand and re-fractured with 60,000 pounds of sand.

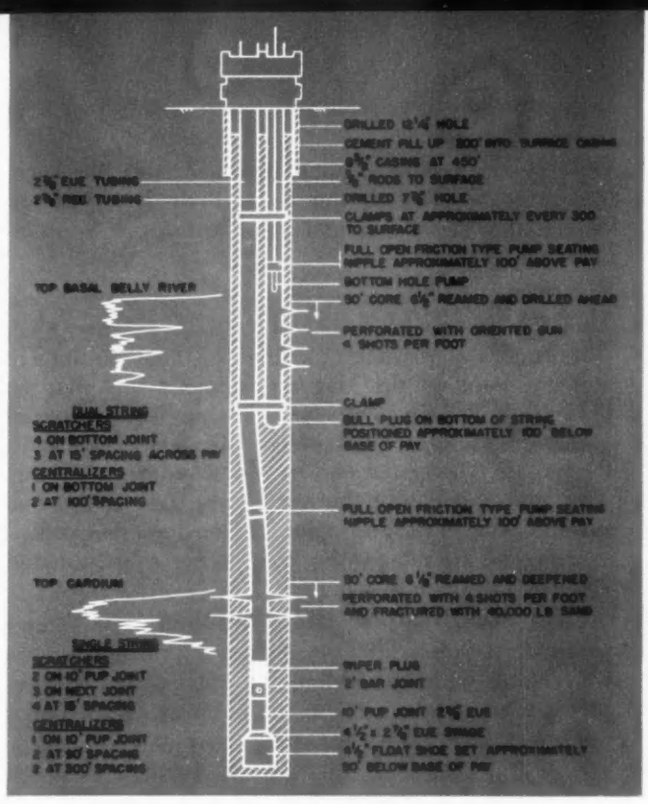

DRILLED 12¼" HOLE
CEMENT FILL UP 300' BYD. SURFACE CASING
8⅝" CASING AT 450'
⅝" RODS TO SURFACE
2⅜" EUE TUBING
2⅜" REG. TUBING
DRILLED 7⅞" HOLE
CLAMPS AT APPROXIMATELY EVERY 300 TO SURFACE
FULL OPEN FRICTION TYPE PUMP SEATING NIPPLE APPROXIMATELY 100' ABOVE PAY
TOP BASAL BELLY RIVER
BOTTOM HOLE PUMP
30' CORE 6¼" REAMED AND DRILLED AHEAD
PERFORATED WITH ORIENTED GUN 4 SHOTS PER FOOT
DUAL STRING
SCRATCHERS
4 ON BOTTOM JOINT
3 AT 15' SPACING ACROSS PAY
CENTRALIZERS
1 ON BOTTOM JOINT
2 AT 100' SPACING
CLAMP
BULL PLUG ON BOTTOM OF STRING POSITIONED APPROXIMATELY 100' BELOW BASE OF PAY
FULL OPEN FRICTION TYPE PUMP SEATING NIPPLE APPROXIMATELY 100' ABOVE PAY
TOP CARDIUM
30' CORE 6¼" REAMED AND DEEPENED
PERFORATED WITH 4 SHOTS PER FOOT AND FRACTURED WITH 40,000 LB SAND
SINGLE STRING
SCRATCHERS
2 ON 10' PUP JOINT
3 ON NEXT JOINT
4 AT 15' SPACING
CENTRALIZERS
1 ON 10' PUP JOINT
2 AT 50' SPACING
2 AT 300' SPACING
WIPER PLUG
2' BAR JOINT
10' PUP JOINT 2⅜" EUE
4½" x 2⅜" EUE SWAGE
4½" FLOAT SHOE SET APPROXIMATELY 50' BELOW BASE OF PAY

FIGURE 5—Associated completion (dual).

Sand-offs have occurred on a few occasions because of equipment breakdowns during the job. Generally it has been possible to flow the tubing clear and, after repairs, start the sand back in and finish the treatment.

Pumping installations. Pumping equipment has been installed on eight slim holes up to this time. Six of these installations have been made on earlier wells not having pump seating nipples in the string. Packer-slip type pump holddowns have been used and, where possible, adapted as top holddowns on RLA pumps. The other two have friction-cup top holddowns.

The only deviation from conventional pumping installations (i.e., tapered rod strings with blade-type scrapers) has been the incorporation of a shear-pin sucker rod safety joint in the rod string immediately above the bottom-hole pump. If a pump becomes stuck in the hole, the safety joint can be sheared and the rod string removed. A macaroni string may be run in to circulate the hole clean to the pump. It is then possible to pull the pump with an overshot and jars.

An installation was made on one well shortly after refracturing. The bottom holddown pump became sanded in. The rod string was pulled out and a macaroni string run in with a very thin-walled washover pipe. The pump was washed over and then recovered with an overshot and jars.

Since this experience, the practice has been to pump wells—at least initially—against a back pressure to minimize any heading tendency which might permit sand slugging.

In the pumping installation, careful consideration was given to possible hazards confronted and some of the preventive measures that could be taken. Most of these measures, such as hollow sucker rods, constituted considerable additional expense contrary to the initial objective of reduced costs. Therefore, to complement the whole slim hole program, it has been our policy to utilize standard equipment wherever possible unless necessity demands otherwise.

Other producing equipment. Both intermitter and plunger-lift installations have been made on slim holes. This equipment has been used successfully to eliminate wire line dewaxing and curb increasing gas oil ratios. Without an annulus to provide a gas source, it is necessary to modify standard equipment with the addition of a small gas volume tank mounted on the flow tee. This tank assumes shut-in well head gas pressure each cycle and provides sufficient gas volume to operate the diaphragm valve.

Economics. Table 1 shows an actual cost comparison between two slim holes and two conventional holes drilled within a half-mile radius in the Pembina field. The maximum spread shows a difference of 42 percent, the medium spread 33 percent. Comparing the actual costs of all our slim holes to offset conventional holes, an average saving of 35 percent has resulted.

Possibly a fair comparison cannot be made in this manner. Many prices changed between the times the two types of wells were drilled. For example, the price of materials has steadily increased; conversely, the price

TABLE 1—Actual Cost Comparison Between Slim Holes and Conventional Holes Drilled on the Same Lease.

Well Name	HB ALDER FLATS 10-8-47-6	HB ALDER FLATS 8-7-47-6	HB ALDER FLATS 12-8-47-6	HB ALDER FLATS 14-8-47-6
Date Well Completed: Total Depth, Feet: Type:	September 1957 5,049 Slim Hole	March 1958 5,123 Slim Hole	October 1956 5,101 Conventional Hole	September 1956 5,088 Conventional Hole
Casing	$ 1,553	$ 1,854	$ 10,355	$ 10,476
Tubing	4,975	5,293	3,856	4,366
Well head	1,688	1,345	2,197	2,120
Miscellaneous materials	845	1,217	730	1,720
Contract drilling and daywork	13,976	17,928	23,752	26,306
Company overhead expense	967	1,616	1,200	1,495
Trucking	1,300	1,365	817	1,714
Outside labor	152	190	383	402
Cementing	2,806	3,588	1,874	1,833
Acid	160	155	495	600
Logging	1,810	893	1,309	1,630
Perforating	987	395	600	638
Coring	140	...	...	300
Fracturing	3,193	3,790	5,817	5,747
Testing	...	...	...	525
Analyses	98	51	...	345
Location expense	2,459	2,818	2,642	4,250
Mud	1,046	1,189	558	1,125
TOTAL	$ 38,155	$ 43,687	$ 56,585	$ 65,592

of drilling has decreased. Therefore, a theoretical cost comparison is shown in Table 2 between a slim hole and a conventional hole using current prices. This theoretical comparison shows that an operator can save 28 percent using the slim-hole method. The graph in Figure 4 shows the total cost of these theoretical wells broken down into four general headings. This illustration indicates the major portion of cost savings in slim holes is realized in materials.

TABLE 2—Cost Comparison Between Theoretical Slim Hole and Conventional Hole Drilled to 5,000 Feet in the Pembina Field

	Slim Hole	Conventional Hole
Casing	$ 1,300	$ 12,100
Tubing	5,300	5,300
Well head	1,100	2,200
Miscellaneous materials (Float equipment, centralizers, etc.)	800	1,200
Contract drilling and daywork	15,800	16,600
Company overhead expense	900	900
Trucking	900	1,800
Outside labor	120	120
Cementing	2,800	2,000
Acid	150	600
Logging	850	850
Perforating	450	350
Fracturing	3,300	4,500
Location expense	2,500	2,500
Mud	1,000	1,000
Core analysis	200	200
TOTAL	$ 37,470	$ 52,220

SAVING: $14,750 or 28 percent

Associated completions. The slim hole completion technique has been further modified and applied to "associated completions." This is a form of dual zone completion whereby two parallel strings of 2⅞-inch tubing are cemented in the same bore hole. This distinction from a dual zone completion is given by the Oil and Gas Conservation Board of Alberta. The significance of this distinction is that semi-annual segregation tests required in dual zone completions will not be necessary in associated completions.

This method of completion was devised for the east edge of the Keystone field wherein two productive sands have been encountered. The Cardium, the lower sand, is thin and not economic to develop on its own. The well program for an associated completion in this area would be as follows (Figure 5).

1. Drill sufficient 12¼-inch hole to set 450 feet of 8⅝-inch surface casing
2. Drill 7⅞-inch hole to total depth, cutting 6½-inch, 50-foot cores through the Basal Belly River at approximately 3,100 feet and the Cardium at approximately 4,100 feet
3. Run open-hole logs
4. Run two strings of 2⅞-inch tubing (long string, EUE —short string, regular) putting the float equipment and bar joint on the long string and a bull plug on the bottom of the short string. Position the bottom of the short string 100 feet below the base of the Belly River pay. Clamp the two strings together at the bull plug, at the collar of the next joint, then at 300-foot spacing to surface. Full open friction-type pump seating nipples are placed in each string approximately 100 feet above the pay
5. Cement down the long string with sufficient volume to fill up 200 feet into the surface casing. Follow the wiper plug with one bbl of oil, 250 gallons of acid, then the remainder oil. Fill the short string with oil
6. After six hours WOC, bleed off pressure and head up
7. Release rig
8. Run gamma ray-collar log. Perforate the short string with an oriented gun. Pressure test the long string. Perforate the long string
9. Squeeze the acid in the long string into the formation and, after a minimum three hours waiting on acid, fracture the Cardium formation with the designed volume.

The two strings of tubing are run together using single elevators and slips on the long string. Pup joints are needed occasionally in the short string to stagger the collars. When adding a joint to the long string, it is necessary to lower the top of the short string below the table. To prevent mud getting into the pipe, a bull plug is screwed in handtight each time.

Non-upset tubing is used in the short string to minimize the center-to-center distance between the two strings. Another advantage of having two different strings was not recognized until running them in the hole. Then different-size collars provided an obvious distinction between the two strings.

At present, three wells have been completed as associated completions in the Keystone field. The long strings are flowing from the Cardium sand and pumping installations have been made in the short strings to obtain production from the Basal Belly River sand. When it becomes necessary to pump the long strings, no difficulty is expected since equipment is available to pump dual string well heads.

This method of dual zone completion provides a means of developing otherwise uneconomic reserves. Compared to a conventional dual zone completion, $13,700 or 18 percent can be saved using this method and continued operating costs of segregation tests are eliminated.

This article is taken from a paper of the same title presented at the Rocky Mountain District Meeting of API, Casper, Wyo., April 1960. The author wishes to express his appreciation to Hudson's Bay Oil and Gas Company Limited for permission to prepare and publish this paper.

—**The End**

About the Author

James Gardner Bonsall was graduated from Oklahoma A&M, now known as Oklahoma State University, where he received a B.S. degree in mechanical engineering in 1954. After graduation he went to work for Hudson's Bay Oil and Gas Company Limited, training first with Continental Oil Company in Wyoming and Oklahoma for 10 months before returning to Hudson Bay's headquarters in Calgary, Alta. At present he is working in Edmonton, Alta., concerned mainly with drilling, completions and production problems. Bonsall is a member of Pi Tau Sigma and Sigma Tau, honorary engineering fraternities, and the Association of Professional Engineers of Alberta.

AN API FEATURE

PART 1 — A STEP-BY-STEP PROCEDURE

HOW TO CONTROL BLOWOUTS

Hazards can be greatly reduced by recognizing threatened blowouts before they occur and using practical, field-tested control procedures

By T. B. O'Brien, Head, Drilling Section, Technical Services
Gulf Oil Corporation, Houston

W. C. Goins, Jr., Section Head, Drilling Research
Gulf Research and Development Company, Harmerville, Pa.

MUCH HAS BEEN written about blowouts, their causes, the equipment used, how to put out fires and other points concerned with the hazards involved. Each writer, after a good start, has said, "Put the well on choke and raise the mud weight." No one has said how much to raise the mud weight or what size choke to use.

The following discussion is a step-by-step procedure for killing only threatened blowouts which, if followed, gives the simplest positive control of the well at all times. Minimum pressures are maintained and a minimum time is required to kill the well. The method has been field tested by the authors and has been found to be practical.

Control of threatened blowouts is dependent upon a number of factors. Among the most important of these, to be discussed in detail later, are the following:

- Thorough training of rig personnel, including "on-the-rig" drills
- Determining the proper choke size and mud weight
- Proper handling of drilling breaks
- Actions to take when a blowout threatens during a trip
- Determining with simple calculations the initial flow rates due to kicks of varying intensity and the conclusions to be drawn therefrom
- Using proper methods of killing threatened blowouts while drilling
- Employing reverse circulation for killing blowouts, a method which has several advantages and disadvantages.

In the field, there is a lack of understanding about the mechanics of a threatened blowout and practically no knowledge of how to kill one. This is clearly illustrated by the usual statement that "nothing happened except that all of a sudden, the well was blowing gas."

Of course, the word "blowout" strikes fear in the mind of everyone from roughneck to chairman of the board. The roughneck fears for his life; the board chairman for his company's bank account. As a result, very few blowouts are approached rationally and there is a strong tendency among rig personnel to leave the rig rather than analyze and correct the situation.

A study has been made of a number of conditions

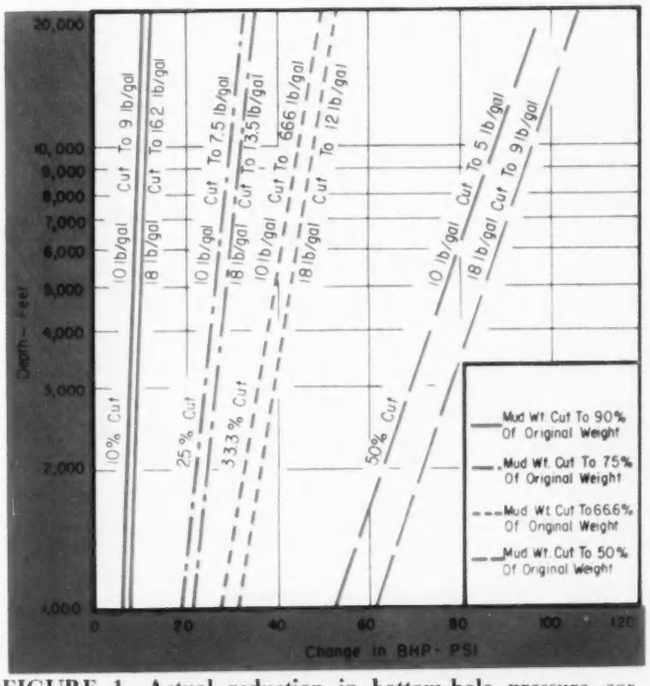


FIGURE 1—Actual reduction in bottom-hole pressure corresponding to a surface observed reduction in drilling mud weight due to the mud being gas cut.

AN API FEATURE

How to Control Blowouts

which lead to blowouts and a method for the correction of each is proposed, leaving little to guesswork. The work of a number of writers is drawn from, but particularly that of Bell,[1] since he is the most comprehensive published to date.

Blowout prevention is not a matter of the number of valves in the preventer system, their arrangement, or the ability of people to operate them. It is a frame of mind existing throughout the drilling crew and supervisory staff. A determination on the part of the operator's management to eliminate blowouts is far more valuable than the addition of several pieces of equipment to control blowouts.

Equipment is much like insurance in the prevention of blowouts. The greater the risk to life and property, the greater the expense required to offset the risk. Blowout preventers should have pressure ratings equal to or greater than any pressure expected in the well being drilled, but they need not be stronger than the casing on which they are installed. Further, at sufficiently frequent intervals, all equipment should be operated and tested. Tests are particularly important after breaking any joint subject to pressure.

Farmer and Jones[2] state that more lives and money can be saved by practical training of crews than in any other manner. As far as rig operation is concerned this is quite true, but training must go beyond the rig; it must go on into company policy. It is true that such policy in general gives lip service to the practice of blowout prevention, but in many cases the policy is devoid of "teeth."

There are two periods in which time is most critical from management's point of view. First, when a contract is being negotiated there is a tendency to belittle the possibility of blowouts in an effort to get a lower price. Second, when drilling slows down, time lost in operation and testing of blowout preventers becomes more important than does the possibility of a blowout.

In either case, dollars are involved. Company policy about the problem always is reflected on the rig. It is necessary that management be certain the supervisory and operating personnel understand and know how to control threatened blowouts. Further, it should be well understood that no unnecessary chances are to be taken either with condition of the equipment or with operation of the well.

By having a general knowledge of conditions to be expected in a well, the individual making the plans can select a satisfactory rig having a crew that is competent to handle the problems that will arise. In selecting the rig he should see the rig in operation if possible. This gives him a chance to observe both the equipment and crew in operation. A simulated kick might be arranged to see how it is handled by the crew.

In some areas various accessory equipment is useful, if not essential, to safe operation. Among these are pit-level measuring devices, mud-weighing equipment, and meters measuring mud both into and out of the well. If gas cutting is expected to be a problem, a degasser will be of considerable value.

These items assume more than convenience value when a well kicks. In fact, on occasion they can, if rigged up properly, give sufficiently early warning to significantly reduce the effective intensity of a kick. In most wildcat drilling they should be considered standard equipment. This is particularly true of pit-level indicators, to be discussed later.

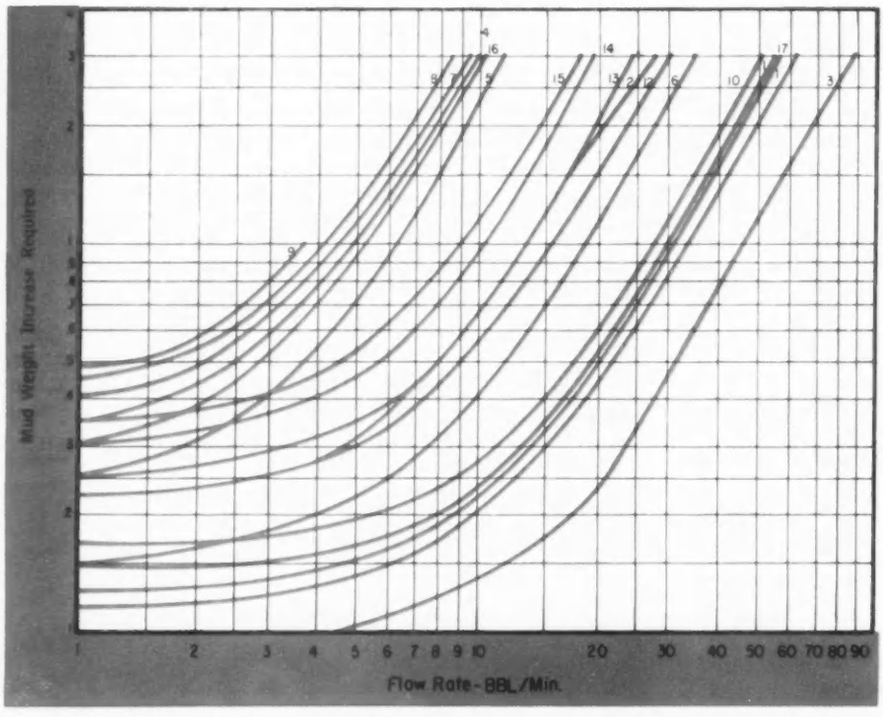
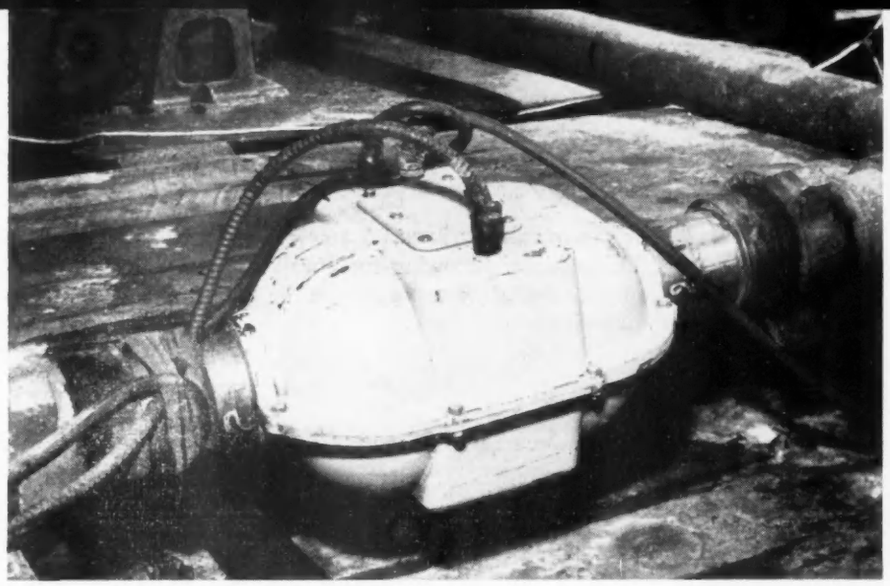


FIGURE 2—Flow rate versus mud weight increase required for various hole sizes and mud weights. See Table 1 for conditions.

Although pit-level devices are fairly satisfactory for mud measurement, a meter which accurately measures mud both in and out of the hole recently has been developed. For critical wells it will supply the utmost in safety, for very small changes in flow rate can be detected and the volume used to fill the hole while making trips can be measured. (See photo, following page.)

Crew training vital. Rig personnel training should consist of two phases. First, each crew should be completely familiar with the care, maintenance, installation and operation of every item of equipment connected with the blowout-preventer assembly. Several operators conduct schools for crewmen, with instruction on equipment being supplied by manufacturer representatives. At a contractor's request, manufacturer representatives will conduct the same type of instruction at the rig, including practical maintenance and handling instructions which



Four-inch electromagnetic transducer flow meter installed on the high pressure mud line between pumps and standpipe. Unit measures, in gallons per minute, total flow of mud to well. A similar unit, but of 6-inch size, is installed ahead of shale shaker and measures the mud outflow. The two signals are transmitted to a single-pen strip chart recorder which integrates them and records the difference in flow. Driller, at any time, can selectively check and record the actual inflow and outflow in gallons per minute.

can lead to appreciable savings in upkeep and replacement costs.

The second phase should consist of "on-the-rig" drills in handling potential blowout situations. These will consist of operating and testing blowout-preventer equipment so that each crew member becomes familiar with each piece of equipment, its function and operation.

Then should come a "pit drill" which will consist of changing the pit-level indicator to simulate a gain or loss. The crew then goes through the necessary steps to prevent a blowout. Usually this will mean picking up the pipe and closing the well in if the well is drilling. If a trip is being made, the operation will be to start back to bottom if a gain has occurred.

The time required by each crew to perform these drills should be recorded. Initial drills may take excessive time, but with practice on the part of the crew and determination on the part of the supervisor, the time required will be cut down. The time required from a readable change in volume to the time the well is closed in should not exceed 2½ minutes. If it does, the crew is slow or the equipment is unsatisfactory.

It will be shown later that time is of the essence in killing a threatened blowout. As discussed by Farmer and Jones, there is a definite need for practice so that many of the operations will become instinctive and thought can be directed toward killing the well rather than operating the equipment.

DRILLING BREAKS

It long has been standard practice, when abnormal pressures are expected, to stop drilling and circulate out every drilling break when drilling in an unproved area. This practice has a very good basis, in that most wells are drilled with a minimum of 0.5 pound per gallon excess mud weight. It is well known that excess mud density, and hence a high pressure differential between the mud column (P_m) and formation (P_f), reduces drilling rate considerably. But when excess formation pressure is encountered and this overbalance is lost, the drilling rate increases. However, formation pressure need not exceed mud pressure to allow drilling rate to increase; the pressures need be only nearly equal, i.e., $P_f \cong P_m$.

It has been established that, for a blowout to occur, it is necessary for formation fluids to flow into the bore hole. This, of course, means that $P_f > P_m$, i.e., formation pressure is higher than mud pressure, and the result will be gain in mud volume in the pit. Should the balance be so close that the annular pressure drop while circulating is sufficient to balance the formation pressure, no flow will occur until the pump is shut down.

Pit level closely watched. What observations are made as a well is circulated following a drilling break?

Generally, a close watch is kept on the pit level to catch any change in level and mud returns are watched for evidence of gas cutting. Bell, in his discussion of blowouts, shows very clearly that gas cutting is very rarely an indication of an imminent blowout. Even 18 ppg mud cut to 9 pounds per gallon will mean less than 100 psi reduction in bottom-hole pressure at 10,000 feet. (See Figure 1.)

Usually, gas cutting will mean one or two things: First, the formation penetrated contains gas; and as it is drilled, a certain volume will enter the bore hole from that section removed by the bit. Quite possibly it could mean that only a small over-balance existed.

Second, a section of very low permeability or a very small section has been opened. These are usually called high-pressure—low-volume sections; it could be shale gas. In either case it is hardly likely that the well will blow out while circulating if reasonable precautions are taken.

Handling drill breaks. Time spent in circulating out each drill break can be reduced—if not eliminated completely—unless it is desirable to circulate cuttings out before drilling continues. Actually, a gain in mud volume —not gas cutting—indicates that the well is coming in. If the well will flow, it will do so as soon as the higher-pressure formation is penetrated. Therefore, the best procedure to follow is:

- As soon as a break is hit, shut down the pump and check the well to determine if fluid is being gained. If so, the well will continue to flow with the pump off; if not, the mud returns will shut off completely. Should returns continue without the pump but no mud is gained with the pump on, no more than 0.4 ppg increase in mud weight will be required to balance the formation. This has been established in the section on *Flow Rates Due To Kicks*. Should the gain persist with the pump on, the well must be closed in and the method given in *Killing Threatened Blowouts* should be used. Should flow cease when the pump is shut down, no change should be made in the mud and drilling should continue.
- Since a drilling break indicates that at least a portion of the overbalance has been lost, the well should be checked before pulling out of the hole to make sure that

it does not swab. This can be done very easily by making a "short trip"—i.e., several stands of pipe are pulled and the bit is run back to bottom. The well then is circulated out. If there is any tendency to swab, the hole will fail to take the proper amount of mud or a severe kick may be noted when circulating out after the short trip. Should the well tend to swab, changes in mud properties other than density may eliminate the condition; if not, the weight can be raised 0.1 or 0.2 ppg.

FLOW RATES DUE TO KICKS

The severity of a kick or threatened blowout is dependent upon three factors:

(1) the magnitude of the pressure differential; (2) length of time fluids are allowed to flow into the bore hole; and (3) the formation-fluid pressure. These three factors determine volume of fluid gained and the pressure with which one will have to work.

The total bottom-hole pressure and pressure differential easily are determined from the drill pipe pressure, as explained later. Inflow rate of formation fluids is controlled by pressure differential, formation permeability, and annular friction drop.

Experience indicates that most formations containing abnormal pressures are sufficiently permeable that it is not the ability of the formation to produce which controls the flow rate, but rather the other two factors. However, many may be tight enough to produce only relatively minor kicks or possibly just gas cutting. Such a well would not show a gain at the rate indicated and generally will not kick while drilling is in progress. At any rate, the pressure differential and annular friction drop are of vital concern.

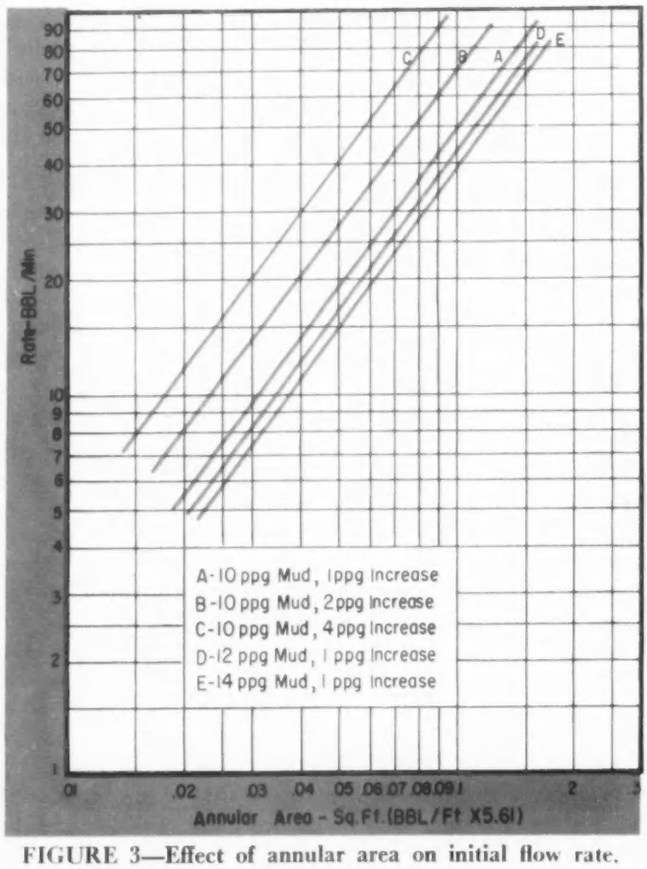


FIGURE 3—Effect of annular area on initial flow rate.

Sample calculations. A few calculations shed light on the problem. Knowing mud weights and pressure differentials, initial flow rates can be determined from the formula:[3]

$$P = \frac{.000086\ \rho\ L G^2}{(D_2 - D_1)\ (D_2^2 - D_1^2)^2} \qquad (1)$$

or, in its rearranged form:

$$G = \frac{\sqrt{P\ (D_2 - D_1)\ (D_2^2 - D_1^2)^2}}{8.6 \times 10^{-5}\ \rho\ L}$$

wherein:

- G = flow rate, gal per min
- P = pressure drop, psi per 100 ft less the pressure differential causing flow = $P_f - (P_m + P_{ca})$
- ρ = density of mud in hole, pound per gallon
- L = length of annulus, feet
- D_1 = minor diameter of annulus, inches
- D_2 = major diameter of annulus, inches

Using Piggott's formula[4] for annular pressure drop and 9.5-ppg mud, the rearrangement becomes:

$$G = \frac{\sqrt{P\ (D_2 - D_1)\ (D_2^2 - D_1^2)^2}}{.0814}$$

If an annular velocity of 140 feet per minute is assumed and, further, that the hydrostatic pressure of the mud column exactly equals formation pressure before the kick is encountered, one can calculate rates of inflow of formation fluid for various pressure differentials and hole-size—drill pipe size configurations. If the pressure differential is calculated on the basis of pounds-per-gallon mud density and P is in psi per 100 feet, and by first determining the pressure loss in the annulus due to circulation at 140 feet per minute, one can find that portion of the pressure differential which can cause additional flow. Then it is possible to calculate the rate of flow it will produce. This determination is good only for the instant flow starts.

After that, conditions in the annulus are changing constantly. If the well is not closed in as more fluid enters the well, pressure differential increases and flow rate increases. The inflow rate at any time can be determined, but it is of little value. The more simple determination of the initial inflow rate is sufficient. Following is a sample calculation of the rate of inflow:

If a 9⅞-inch hole is being drilled using 4½-inch OD drill pipe and 10 pounds per gallon mud, with annular velocity of 140 feet per minute and circulating rate of 440 gallons per minute when abnormal pressure is encountered equal to 1 pound per gallon mud weight above the hydrostatic pressure of the mud in use:

Pressure loss in 9⅞-in. × 4½-in. annulus = 0.6 psi per 100 ft.
Pressure differential due to abnormal pressure = 5.2 psi per 100 ft.
Remaining excess differential = 4.6 psi per 100 ft.
Then: P = 4.6 psi per 100 ft.

$$G = \frac{\sqrt{(9.875 - 4.5)\ [(9.875)^2 - 4.5)^2]\ 4.6}}{.0814 \times \frac{10}{9.5}}$$

$$G = \sqrt{1.72 \times 10^6} = 1.32 \times 10^3 \text{ gal per min} = 31 \text{ bbl per min}$$

TABLE 1—Flow Rate for Kicks of Varying Intensities

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	AV ALL CASES 140 FEET PER MINUTE						FLOW RATE			FEET FILLED PER MIN.		INCHES IN PIT			
												10 Bbls/In.		2.5 Bbls/In.	
CURVE NUMBER	Hole	Drill Pipe	W_1	Mud Weight = $\triangle P_A$	Gpm At 140 FPM	Bbls/Min. @ 140 FPM	.5 PPG BPM	1 PPG BPM	2 PPG BPM	.5 PPG	2 PPG	.5 PPG	2 PPG	.5 PPG	2 PPG
1	9⅞	4½	10	.11	440	10.5	22	31	49	296	660	2.2	4.9	8.8	19.6
2	8½	4½	16	.25	300	7.15	8.1	13	21	163	424	.8	2.1	3.2	8.4
3	12¼	5	12	.09	710	16.9	37.8	56.2	86.5	260	562	3.1	6.8	12.4	27.2
4	6	3½	14	.32	140	3.34	2.52	4.95	7.8	112	347	.2	.78	.8	3.2
5	6	3½	10	.23	140	3.34	3.76	6.3	9.5	167	488	.3	1.1	1.2	4.4
6	8½	4½	10	.15	300	7.15	12.2	18.7	27.8	246	560	1.2	2.8	4.8	11.2
7	6	3½	16	.37	140	3.34	2.16	4.5	7.2	96	320	.2	.7	.8	2.8
8	6	3½	17	.40	140	3.34	1.72	4.2	6.9	76	307	.1	.7	.4	2.8
9	6	3½	18	.42	140	3.34	1.55	3.7	....	69	....	.1	....	.4	....
10	9⅞	4½	14	.16	440	10.5	17.6	27.6	41	236	551	1.7	4.1	6.8	16.4
11	9⅞	4½	12	.14	440	10.5	19.6	30	44.5	264	600	1.9	4.4	7.6	17.6
12	8½	4½	14	.215	300	7.15	9.2	15.2	23.4	185	473	.92	2.3	3.7	9.2
13	7⅞	4½	10	.21	240	5.7	8.02	13.3	20	202	505	.80	2.0	3.2	8.0
14	7⅞	4½	14	.30	240	5.7	5.7	10.6	15.5	144	392	.57	1.5	2.3	6.0
15	7⅞	4½	16	.34	240	5.7	4.75	9.6	14.3	120	362	.47	1.4	1.9	5.6
16	6	3½	12	.28	140	3.34	3.0	5.5	8.3	133	369	.30	.83	1.2	3.3
17	9⅞	4½	11	.12	440	10.5	20.2	30.5	45.2	256	590	2.02	4.52	8.00	10.0

TABLE 2—Annulus Pressures When Varying Volumes of Formation Enter Bore Hole

Well Depth	Mud Weight	Mud Weight Required	P_{dp}	P_a for the Following Volume Gained, bbls.					Initial Flow Rate (bbls/min)	Fluid	Hole Size	Drill Pipe Size
				25	50	100	150	200				
10,000	10	12	1040	1250	1470	1900	2300	2700	41	Gas	9⅞	4½
10,000	10	12	1040	1075	1110	1180	1250	1320	41	Water	9⅞	4½
6,000	10	12	624	670	720	813	910	1005	27.5	Gas	8½	4½
15,000	16	17.5	1065	1485	1900	2325	2750	3175	17	Gas	8½	4½
15,000	16	17.5	1065	1275	1485	1700	1900	2100	17	Water	8½	4½
15,000	14	16	1560	2170	2780	4000	5220	6440	7.8	Gas	6	3½
15,000	14	16	1560	1820	2080	3600	4120	4640	7.8	Water	6	3½

Curves show data. Using this method, calculations were made at various mud weights and hole sizes. The group of curves in Figure 2 was obtained. Selected data from Figure 2 are shown in Table 1 with certain other pertinent data. Table 1 shows the terrific increase in annular flow rate when excess pressure is encountered. Although the curves and table have no value in the actual control of a well, they do point out several interesting conditions. For example, the intercept on the vertical axis is equivalent to the mud-weight differential which will produce a flow of one barrel per minute into the bore hole. In every case that mud weight is within 0.1 pound per gallon of that which will not cause flow (Col. 5, Table 1), so long as circulation continues at an annular velocity of 140 feet per minute.

It will be noted that in most conditions of hole and drill pipe size and at 10 pounds per gallon mud density, flow into the bore hole will occur while circulating when formation pressures in excess of static bottom-hole mud pressure by 0.15 ppg are encountered.

As the annular area decreases and/or the mud weight increases, the formation to borehole pressure differential ($P_f > P_m$) required to cause flow (while circulating) increases. This is illustrated by curves 1, 4, and 5 in Figure 2. Curve 1 is based on 9⅞-inch hole, 4½-inch drill pipe, and 10 ppg mud. Curve 5 is based on 6-inch hole, 3½-inch drill pipe, and 10 ppg mud. Curve 4 is based on 6-inch hole, 3½-inch drill pipe, and 14 ppg mud. Each case illustrated, except 12¼-inch hole, 5-inch drill pipe, and 10 ppg mud (and this one would be very close), requires a pressure-differential increase in excess of 0.1 ppg to start flow. One (Curve 9) requires almost 0.5 ppg to start flow.

It has been established that very few formations have pressures equivalent to a gradient in excess of 0.95 psi per foot (18.3 ppg mud weight), in which case a well drilling with conditions as in Curve 10 (6-inch hole, 3½-inch drill pipe, 18 ppg mud) could not blow out while the well is being circulated. However, for all of the curves shown, a kick requiring an increase of more than 0.5 ppg cannot be killed by the circulating annular pressure drop and the well must be closed in.

In most normal operating cases 0.1 to 0.25 ppg is the maximum mud-weight differential that can be overcome by circulating with the well open. This indicates, therefore, that the well must be closed in if any mud is gained while drilling. Figure 3 shows the effect of annular area, initial mud weight, and differential pressure on the flow rate.

Circulating rate comparison. Further, as can be seen, a small increase in mud weight required over that necessary to start flow will cause a very large influx of fluid from the formation. Table 1 shows a comparison of the circulating rate in barrels per minute at 140 feet per minute annular velocity (Col. 7) and the influx rate or rate of gain when 0.5, 1, and 2 ppg (Cols. 8, 9, 10) increased mud weight are required to balance formation pressure. This clearly shows that, at a differential of 1 ppg, the rate of gain will be such that pit level change will be noticeable in a matter of a minute or so when large-size holes are being drilled.

On the other hand, when drilling a small hole (6-inch hole, 3½-inch drill pipe), if a pit having a capacity of 10 barrels per inch is being used and a kick requiring as much as 2 ppg increase in mud weight is encountered, an increase in pit volume of less than an inch will occur in the first minute (Col. 13). During the same period approximately 400 feet of hole will be filled by formation fluid (Col. 12). Here two things are indicated:

First, very few kicks encountered actually require more than 1 ppg increase in mud weight. This is believed to be the case because of the terrific flow rate that would be produced by kicks of greater intensity. It is

quite rare that such flow rates as are encountered with kicks requiring 2 ppg density increase are witnessed. Usually, the reason for larger increases in mud weight is that an excessive period of time elapses between the time high pressure is encountered and the time it is recognized by the crew.

It is highly probable that a large majority of kicks actually require 0.2 to 0.5 ppg increase in density to balance the formation pressure. Additional mud-density increase is added intentionally or unintentionally as a safety factor. Apparently this safety factor may amount to as much as 2 or 3 ppg on occasions. It is this "safety factor," coupled with higher pressure surges resulting from higher-density mud, inaccurate weighing of mud resulting from gas entrainment, and poor control of well pressures, that cause the loss of circulation that so very often accompanies the killing of a threatened blowout.

Second, active mud pit size should be determined by the sizes of hole being drilled and the drill pipe being used. Extra mud can be kept readily available on the location if it is desired, but the following are believed to be reasonable pit sizes for holes of approximately the sizes indicated:

Hole Size, Inch	Drill Pipe Size, Inch	Mud Pit Capacity Barrels Per Inch
12¼	4½ or 5	10 to 15
9½ to 12¼	4½ or 5	10
7½ to 8½	4½	5
6 to 7	3½	2½

This arrangement will serve two purposes. It will give sufficiently early warning of the well kicking, and will allow for better control of measuring drill pipe displacement as it is pulled.

Put well on choke. Probably the most significant thing to be learned from the flow rates shown here is that it is imperative that blowout preventers be closed as rapidly as possible when a well starts to come in. Further, when the well is closed in it should then be opened on a suitable choke rather than be gradually pinched down. To illustrate this, the following examples are given in Table 2. It is shown that, with no more than 1 ppg mud weight increase required, in a matter of 3 minutes considerable pressure can be built up on the annulus.

Even in the case of a shallow well, within 5 minutes pressure can be over 1,000 psi if a gas kick is encountered; and in the process of killing the well, it will be necessary to allow gas in the annulus to expand and permit the annulus pressure to rise somewhat. It is quite possible that, if sufficient foreign fluid enters the bore hole before the well is closed in, the annular pressures may reach a sufficiently high value to exceed either the formation-breakdown strength or the working pressure of the blowout preventers.

When the well is deep and there is little open hole, the high pressures indicated in Table 3 for such conditions may cause leaks in blowout preventers that have not been properly tested. Shallow casing settings and long open-hole sections would lead to formation breakdown when the well is closed in. Increased volumes of formation fluid entering the bore hole aggravate both conditions.

TABLE 3—Mud Required to Control Well with Pipe at Depth Shown

Pipe Pulled from 15,000-10,000 ft. and Returned to Depths Shown

Depth (Feet)	Mud Weight Required at Percent Volume Swabbed*				
	5 Percent	10 Percent	25 Percent	50 Percent	100 Percent
10,000	15.4	15.8	16.9	18.8	22.5
11,000	15.4	15.7	16.7	18.4	20.5
12,000	15.3	15.6	16.6	18.1	18.7
13,000	15.3	15.6	16.5	17.2	17.2
14,000	15.3	15.5	16.1	16.1	16.1
15,000	15.0	15.0	15.0	15.0	15.0
Mud Pressure Last Ps:	200	400	1000	2000	4000

* Assumed foreign fluid has no appreciable density.

The ideal case is to close the well in before any mud is gained. Although this cannot be done, it can be approached. If the pit is sized properly to the hole size being drilled, or if a satisfactory mud-metering device is in use, the driller will know within less than a minute from the time fluid starts to enter the hole that the blowout preventors must be closed. No more than one minute should be required to close the well in. It will be much easier to reopen the well and resume circulation after closing it in for apparently valid reasons than to overcome the pressure increase caused by the influx of an extra 50 to 100 barrels of formation fluid.

This article from "The Mechanics of Blowouts and How to Control Them" by T. B. O'Brien, Gulf Oil Corporation and W. C. Goins, Jr., Gulf Research and Development Company, presented at Southern District Spring Meeting, Division of Production, API, San Antonio, Texas, March 16-18, 1960.

TO BE CONTINUED

About the Authors

T. B. O'Brien was graduated from Louisiana State University in 1948 with a B.S. degree in chemical engineering. In the same year he joined the Engineering Department of Gulf Oil Corporation and worked as mud engineer and drilling engineer in various South Louisiana and Texas areas. He advanced to his present position as head of the drilling section of Technical Services of the company's Domestic Production Department. He is a member of API and AIME.

W. C. Goins, Jr., was graduated in 1942 with a B.S. in chemical engineering from Texas A&M. After a 3½-year tour of duty with the U.S. Army, he joined Gulf Oil Corporation in 1945. For two years he worked in drilling and drilling mud technology in South Louisiana, Houston and West Texas. From 1947 to 1958 he was supervisor of the drilling section of the company's Technical Services Laboratory in Houston. From 1958 to the present he has been section head, Drilling Research, Gulf Research and Development Company at Harmerville, Pa.

AN API FEATURE

HOW TO EVALUATE CURRENT FINDING COSTS

This new way to determine replacement cost trends will help your company plan exploration and production programs more wisely and gain knowledge of future profits

By R. E. Megill, Senior Economist, Carter Division
Humble Oil & Refining Company, Tulsa

MONEY SPENT by the producing phase of the petroleum industry easily separates into three distinct functions:

- Searching for new reserves
- Developing reserves already found
- Operating producing properties already found and developed.

Individuals and companies maintain numerous expense records on these three functions for income tax purposes and for their own requirements. However, there are several problems inherent in the correct interpretation of exploration data, i.e., because of the natural separation of the expenditures listed above, most oil companies use approximately the same factors in compiling various costs.

One of the most serious problems in determining exploration expenses is that of finding the current exploration cost per barrel. Although costs associated with exploration can be segregated, the barrels to which these dollars should be applied are not readily available.

Oil companies have related their yearly exploration expenses to as many as three different groups of barrels; these are:

1. Number of barrels produced
2. Total number of barrels added to reserves
3. Number of barrels found.

The barrels produced by a company each year are derived from discoveries of all years. Therefore, a comparison of current exploratory costs to these barrels is meaningless unless the company happens to be replacing by current exploratory efforts exactly the same number of barrels as are produced.

The barrels added to reserves each year are composed

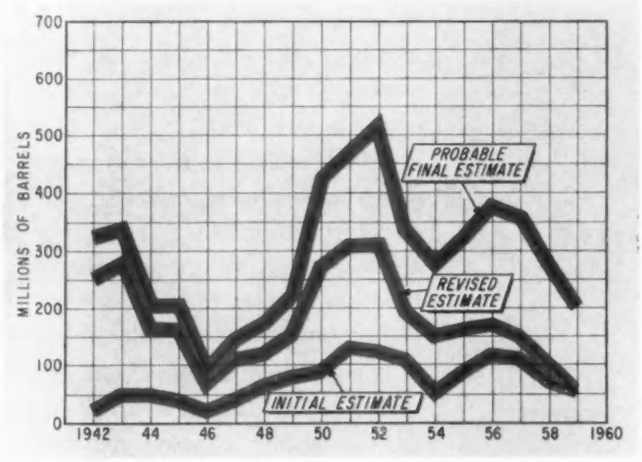


FIGURE 1—Primary reserves discovered in Rocky Mountains. (3-year weighted industry average)

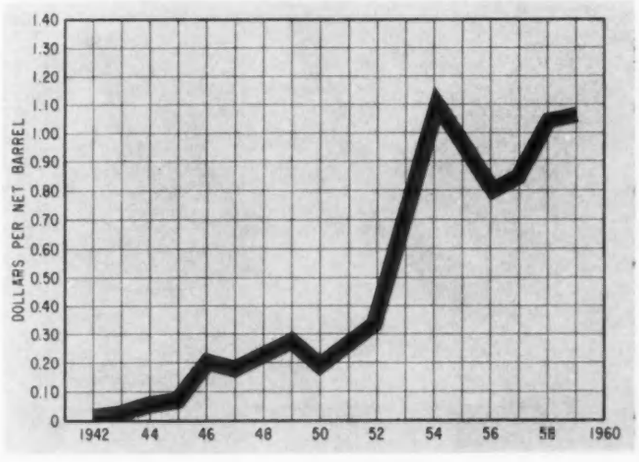


FIGURE 2—Cost of finding primary and secondary reserves in Rocky Mountains. (3-year weighted industry average)

AN API FEATURE

Evaluate Current Finding Costs

of new discoveries, extensions to prior years' discoveries, and revisions of older discoveries. The revisions also include secondary recovery additions to reserves. Many of the additions to reserves each year have no real relationship to current exploration funds, so these barrels also produce an unsatisfactory answer.

The logical barrels to relate to current exploration funds would seem to be the number of barrels found each year. This would give a direct measure of the results of money spent looking for new reservoirs.

Why aren't these barrels used? The primary reason is that the quantity of barrels found is not immediately known. Although the initial estimate of reserves is based on the best information available, it is usually substantially smaller (on the average) than the final estimate. Thus, any finding cost per barrels based on initial estimates would be unreasonably high.

The solution. The Carter Division of Humble employs a system—developed by J. R. Arrington—believed to be the best solution to the problem of getting a reasonable estimate of the current finding cost per barrel. In Carter Division's Economics Department, reserve estimates are maintained for all fields in the territory in which it operates. On a subsidiary record, the fields are grouped by year of discovery and tabulated each year-end as *revised* estimates.

For example, assume a new field is discovered in the year 1950. For the new field, a reserve estimate of 10 million barrels is recorded at year-end 1950 and is called the *initial* estimate. Suppose in 1953 a reappraisal of the field indicates an upward revision to 15 million barrels is needed. The new estimate of 15 million barrels, recorded at year-end 1953, is called the *revised* estimate.

The 1953 revised estimate is the latest record of oil discovered in 1950. The additional oil was actually there in 1950 but could not be evaluated at that time. A revised estimate system (one which applies to all revisions back to the year of discovery) thus provides current estimates for discoveries of all years.

Historic growth rate. The crux of the system involves calculating the historic growth rate of past discoveries. This rate is applied to the latest revised estimates to arrive at what is called *probable final* estimates. The adjusting factors always are applied to revised estimates; they are large for recent discoveries and gradually diminish with time. Waterflood adjustments can be adapted to this system.

The three types of estimates are shown on Figure 1. The discoveries for the Rocky Mountains are shown for the period 1942 to 1957 based on Humble's records. The bottom line is the initial estimate, the dashed line above is the revised estimate and the top line is the probable final estimate.

It is obvious that each set of estimates produces a different cost of finding per barrel. Since the revised estimates are constantly being changed as new production and development data become available, the probable final estimate provides the most constant and reasonable cost of finding per barrel.

How reliable and constant are probable final estimates? Following is an example: In 1956 Carter Division's probable final estimate of reserves discovered for Kansas and Oklahoma for the period 1942-1955 was 3.7 billion gross barrels (excluding unbooked-waterflood reserves). Three years later the estimate of P.F. discoveries for the same period was 3.5 billion gross barrels. The new estimate changes the cost of finding estimate only 4 cents per net barrel.

It is obvious that this is a statistical solution to the barrel problem. It is more accurate if a large quantity of numbers are involved. It cannot be applied to a specific field or to a small area; yet it provides the best means of telling management what a company's exploration costs are.

This system could be used by any company willing to take the time to group its reserve estimates by year of discovery. From this grouping (after a few years of history are available), the growth rates could be computed, and probable final estimates obtained.

The chief advantage of the system is that it provides an estimate of the current cost of finding per barrel, thereby enabling the company to evaluate its exploration cost trends.

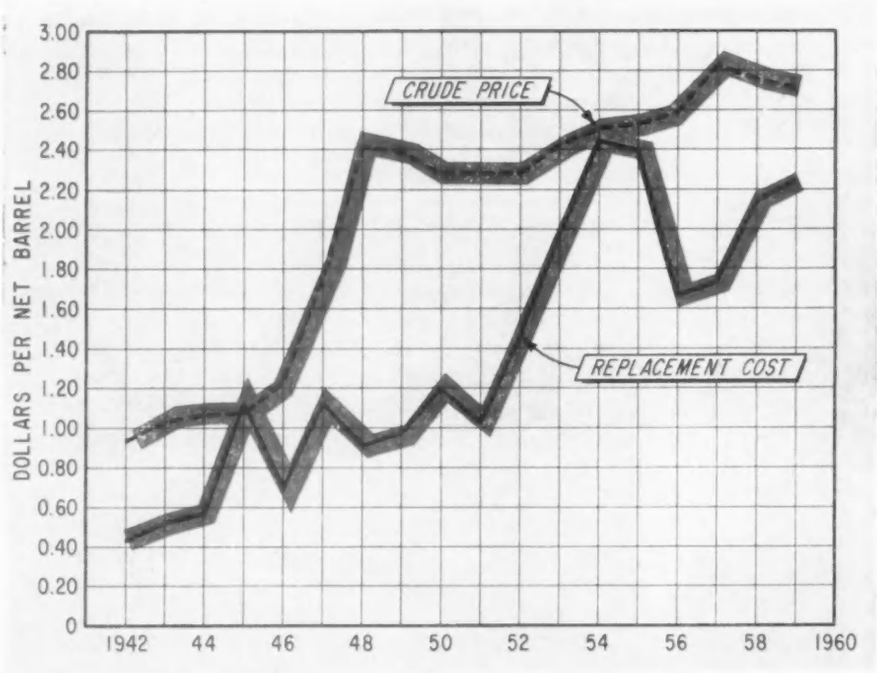


FIGURE 3—Replacement cost versus crude price in Rocky Mountains. (Industry average)

Its disadvantages are that it requires the maintenance of an additional reserve record and that it cannot be explained quickly or simply. Like many new ideas, it takes time to convince people that it is better than the system being used.

Allocation of finding costs to gas. In relating barrels found to money spent looking for new reserves, the question of how to allocate finding costs to gas arises. No attempt is made in this paper to allocate costs for gas found.

Because of the complexity of the problem, no single allocation method has been found which is acceptable to all. The costs shown include the total cost of finding oil and gas.

Those interested in correcting errors resulting from combining the costs should apply their own allocation techniques to finding costs. Such allocation, however, should not affect the general conclusions concerning the trends in finding and replacing costs.

More than company reserves needed. Just knowing the company's crude reserves discovered and its cost of finding is not enough. Every company needs an outside standard of measurement:

Are the company's costs higher for the area lower or equivalent to that of the industry?

How do the company's costs compare with other companies?

Some record of what the petroleum industry is doing is needed for comparison.

The petroleum industry is just awakening to the fact that sufficient data are available to measure the dollars spent by the industry in the search for new oil properties. The Joint Survey data published by the API, IPAA, and the Mid-Continent Oil and Gas Association have shed considerable light on the problem of determining industry expenditures.

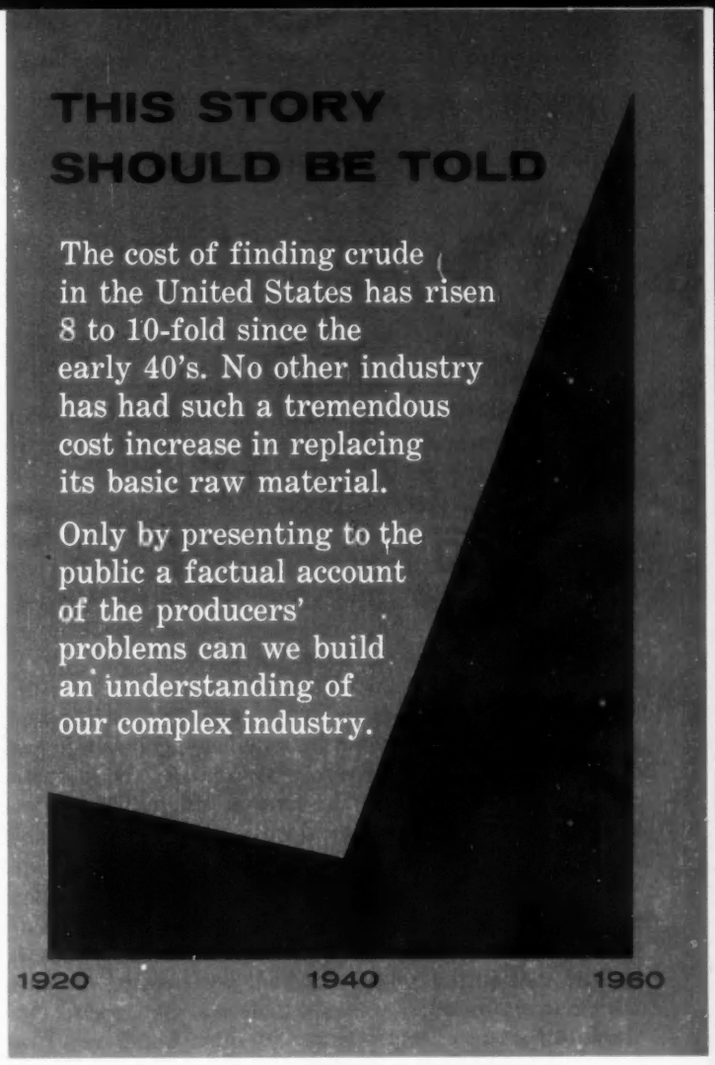
The initial survey showed how much was spent in exploration, development and production in the United States for 1944, 1948 and 1953. Similar data have been recently released for the years 1955 and 1956.

However, the Survey data can be duplicated by a completely independent method. Industry's expenditures can be estimated by applying unit costs to the physical factors associated with the Industry. These physical factors are the number of geologists, the amount of geophysical work performed, the number of wells drilled, the number of acres held by major companies and the industry. All of the data can be obtained from published sources.

Applying unit costs to the physical factors enables an estimate of the following expense items which we include in the cost finding:

- Geological costs and scouting costs
- Geophysical costs
- Leasing costs
- Lease rentals
- Value of leases surrendered
- Test well contributions
- Dry hole losses.

To utilize the cost data it must be related to barrels found. This, of course, requires a reserve organization which follows industry reserves by fields.


THIS STORY SHOULD BE TOLD
The cost of finding crude in the United States has risen 8 to 10-fold since the early 40's. No other industry has had such a tremendous cost increase in replacing its basic raw material.
Only by presenting to the public a factual account of the producers' problems can we build an understanding of our complex industry.
1920
1940
1960

If the proper reserve data are available, the exploration expenditures derived as explained can be related to probable final barrels to establish finding cost trends.

Industry cost of finding per barrel. Based on data developed from Carter Division's analyses and reserve records, the cost of finding per net barrel is shown on Figure 2 for the Rocky Mountain area. This area is considered one of the favorable areas for oil exploration in the United States. Relative to some other areas, its cost per barrel is lower; yet its finding costs have increased rapidly since 1950 from 20 cents per barrel to more than $1 per barrel today.

It is most important for the industry (as well as people outside the Industry) to know its cost of finding per barrel. The petroleum industry has been handicapped as few other industries are by lack of current data on the results of its exploratory efforts.

If for lack of current data management must wait five years before finding costs per barrel can be determined, the proper investment decisions cannot be made. These facts can be estimated currently by the method described.

Replacement costs. There is another reason for studying the cost of finding; it represents a significant part of the Industry's replacement cost.

For the oil producer, replacement cost is the sum of finding, developing, and operating costs per barrel. Three

different barrels are involved. Barrels found are related to finding costs, barrels developed by oil wells are related to development cost and oil produced is related to operating cost.

The reason for the three different groups of barrels is the need to reflect current replacement costs. If an oil company wants to stay in business it must find, develop and produce a new barrel to replace those sold; and the new barrel is replaced at today's cost.

All industries face the problem of high replacement costs. This problem is much more acute for the petroleum industry because of the risk factors affecting the cost of finding; rising risks compound the effects of inflation.

In the United States, since the early 40s the cost of finding crude oil per barrel has increased from 8 to 10-fold. As far as is known, no other industry has had such a tremendous cost increase in replenishing its basic raw material. This is the type of information the industry should make available to the general public. Only a factual presentation of the producer's problems can build an understanding of our complex industry.

The replacement cost per barrel reflects the cash spent by the industry related to the proper barrels. As such it is not an indicator of current booked profits; it is an indicator of future profits. It deals with costs associated with barrels found, most of which will be produced in the future; corporate profits on the other hand stem from barrels produced which are derived from discoveries of the current year and all prior years.

If the industry is to supply its share of the future energy requirements, the replacement cost per barrel must be kept below future crude prices. The cost of a commodity is eventually reflected in its selling price. This is true of steel and most of the other items which the industry must buy. However, because of competition among the crude oils of the United States, competing crudes in other parts of the world and competing energy sources, the oil producers in a given area cannot always expect crude price increases commensurate with replacement cost increases.

This forces producers to reduce costs. It is impossible to determine the extent to which costs must be reduced by the industry unless the cost of replacement for that area is available.

Replacement cost per barrel. To illustrate the cost-price relationship, the replacement cost per barrel and average crude price are shown for the Rocky Mountains on Figure 3.

As mentioned, replacement cost per barrel is the sum of operating, developing and finding cost per barrel. In the Rocky Mountains for recent years, finding cost is about 45 percent of replacement cost per barrel, with development cost and operating cost amounting to 20 percent and 25 percent, respectively.

In the Rocky Mountain area, current replacement costs are below crude price. There are other areas where replacement cost is equal to or greater than crude price.

In all areas since 1950, replacement costs have increased more rapidly than crude price. In the Rockies, the replacement cost per barrel has increased from $1 in 1950 to $2.25 at present. Such cost trends are significant in planning for the future.

Other uses of data. There are many uses for data available from replacement cost analyses. Some of these are:

- To optimize budget expenditures
- To provide a basis (with other data) for calculating current and future rates return on exploration expenditures
- To establish yardsticks for purchasing properties
- To supply useful information for dissemination of knowledge about the oil industry
- To provide cost trends to aid management in planning for the future.

Such analyses are one of the challenges to today's management advisory groups. The challenge is ever present to lift our heads above the data maintained and devise methods to show what they mean, how they can be used to see where we are and where we are going.

In this day and age, it is almost impossible for a company to survive unless it provides for growth. The company which best knows its cost position and that of its industry and competitors can adapt the changes constantly occurring to enable the company to grow.

Traditional accounting concepts do not tell an oil company the cost of replacing its crude oil inventory. Nor do they reflect future profits. By using available data and deriving replacement cost trends, an oil company can plan wisely its exploration and production programs—and gain some knowledge of future profits.

This article taken from "The Evaluation of Current Finding Costs" by R. E. Megill, senior economist, Carter Division of Humble Oil & Refining Company, presented at Rocky Mountain District Spring Meeting, Division of Production, API, Casper, Wyo., April 21, 1960.

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About the Author

Robert E. Megill attended Oklahoma University and received his B.S. degree in geological engineering from Tulsa University. He was employed by The Carter Oil Company in 1941. Before his promotion to senior economist and head of the reserve economics section of the economics department, he was a senior reserve geologist for Carter. A member of AAPG, he has written several society papers, including "Selected Statistical Uses of AAPG Membership List," "How Much Does It Cost to Find Oil," "Crude Oil Replacement Costs in the Illinois-Michigan Basin Areas," and "How One Company Determines Cost."

AN API FEATURE

STOCK TANK VAPOR RECOVERY INCREASES LEASE INCOME

Consolidating lease tank batteries and installing small, automatically operated compressors, permits recovery of rich stock tank vapors

By R. C. McCutchan, Staff Assistant, Natural Gasoline Department
Phillips Petroleum Co., Houston

CONSOLIDATION of lease batteries for LACT installations, unitization and cost-cutting programs have made available large volumes of rich stock tank vapors. Using small skid-mounted compressor units, many operators can recover, compress and inject these vapors into the gasoline plant gathering system, converting what formerly was a total loss into an attractive source of lease income.

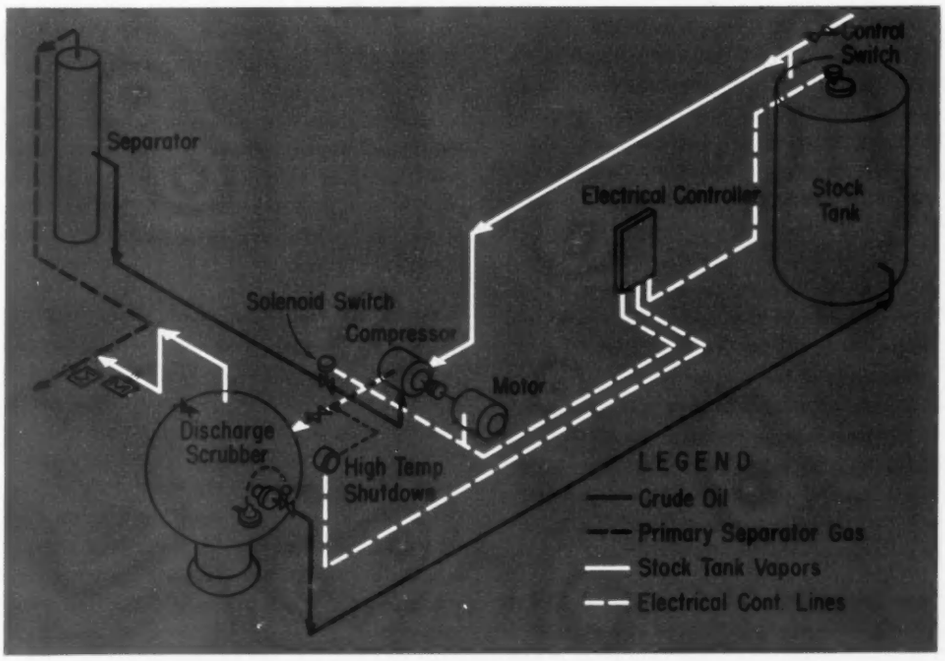
Important factors involved in the installation of these vapor recovery units include:

• Evaluations for such installations are based on the casinghead gas contracts which cover the leases involved. The only data required are measurements of the volume of stock tank vapor and a test car (compression) hydrocarbon content.

• Reservoir conditions, lease operation and production rates may affect the volume and content of stock tank vapors, so caution should be used in applying test data over a large area.

• Several types of compressor units are available. Electrically driven units currently used by Phillips Petroleum Company are equipped with emergency controls and operate automatically.

The recovery of lease battery stock-tank vapors only recently has stimulated sufficient interest to investigate the economics involved in the recovery of rich hydrocarbon vapors. Perhaps the most important change in current lease operation that contributes to this interest has been the widespread installation of the lease automatic custody transfer—LACT—batteries and consolidation of field batteries for unit operations or, for the resultant labor and maintenance savings involved. These installations in West Texas, and especially on Phillips' leases, usually involve the combining of several smaller batteries



Schematic flow diagram of vapor recovery unit.

AN API FEATURE

Stock Tank Vapor Recovery

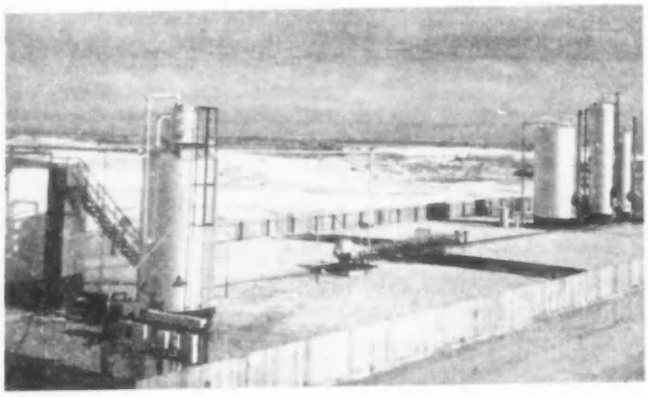


FIGURE 1—Over-all view of Phillips University Andrews County lease showing LACT installation with vapor recovery unit in center foreground.

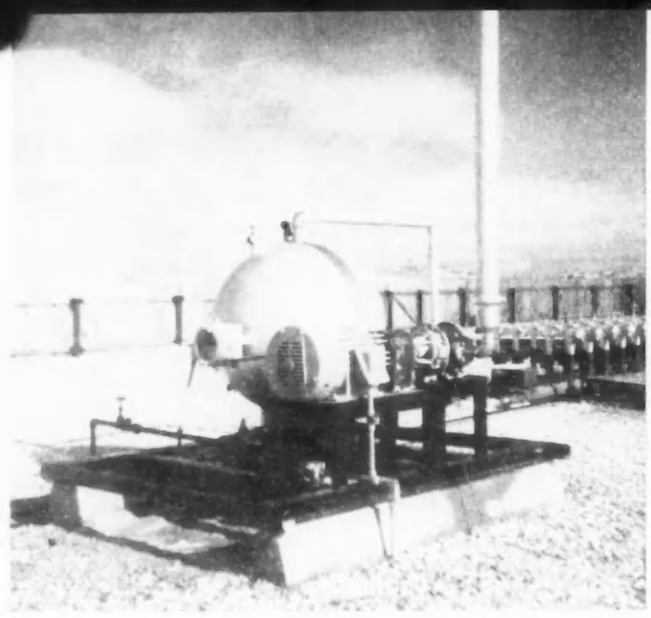


FIGURE 2—Close-up view of 20-horsepower, 130 Mcf per day capacity liquid seal compressor on Phillips University lease connected to the company's Goldsmith gasoline plant.

on one lease which results in a total combined oil production at one battery of from 500 to 2,000 barrels per day of crude oil. These relatively large volumes of oil, processed through normal lease facilities, usually provide a sizeable quantity of extremely rich hydrocarbon vapors at convenient locations for recovery and injection to gasoline plant gathering systems.

The first installation in which Phillips became interested was one installed in 1956 in Lea County, New Mexico, by the Phillips Production Department on the Denton lease. Since this lease is connected to Atlantic's Denton gasoline plant system, the Phillips Gasoline Department participation was limited to observation. The unit still is in operation, although, as with many new equipment applications, numerous changes, modifications and improvements have been made over the intervening years.

Compressor types. Currently, several different types and makes of compressors are in service in West Texas. Phillips has installed two liquid seal rotary compressors. Others have used small positive-displacement type rotary and reciprocating units, as well as the larger, conventional slow-speed reciprocating units. Most of them are driven by electric motor, either direct-connected in the case of the rotary units or through V-belt drives on reciprocating units.

There is no one make or type applicable to all vapor recovery installations. In specifying equipment for this service, many factors come into consideration that will influence the final selection of the make and type of unit.

Installation and operation of the vapor recovery equipment is the responsibility of the primary oil producer. Most of the larger batteries will provide an attractive economic operation for the oil producer. The equipment is physically connected to and dependent upon the lease operation. The producer therefore must furnish the initiative for these installations.

Liquid condensation problem. Initially, the problem of liquid condensation in the suction line to the compressor, especially during cooler weather, created hazardous conditions on the positive displacement type units. Equipping installations with adequate vapor-scrubbing capacity and automatic high liquid-level shutdown equipment will overcome these handicaps.

Condensation in the suction lines resulted in Phillips' selection of the liquid seal units for the first installations. These units operate with a flow of liquid seal fluid through the compressor. In fact, the fluid acts as a compression agent rather than the impeller or rotor. Therefore, it was decided that operating a unit that could tolerate fluids during compression would offer a distinct advantage over the positive-displacement types. However, Phillips' experience has indicated that these units require approximately twice the horsepower to compress the same volume of vapors through the same compression ratio that is normally calculated for conventional reciprocating units. The performance of these units has been trouble-free and they require little, if any, attention for operation and maintenance.

It should be mentioned here that this last statement is not entirely true because of a mechanical failure of an auxiliary pump furnishing seal fluid to the first installation. The compressor overheated and was completely destroyed by fire. This overheating condition had been observed before the disaster when seal fluid was either restricted or shut off. Automatic high-temperature shutdown equipment was on order at the time of the incident. All units are now installed with these shut-down devices.

Crude oil as fluid seal. The first unit used produced crude oil as seal fluid. This crude oil was taken as a sidestream from the discharge of the monitor pump on the LACT installation. A small ¼-horsepower centrifugal pump was installed as a part of the vapor-recovery unit that fed this oil to the compressor. It was a failure in one of these pumps that resulted in the loss of seal fluid and subsequent overheating. The replacement unit at this installation was piped to obtain the crude oil seal fluid directly from the separator upstream on the level-control dump valve. This made available the full 20 to 25-psi separator pressure for flow of this fluid to the compressor. Seal fluid is commingled with the vapors into a discharge scrubber where it is automatically separated and

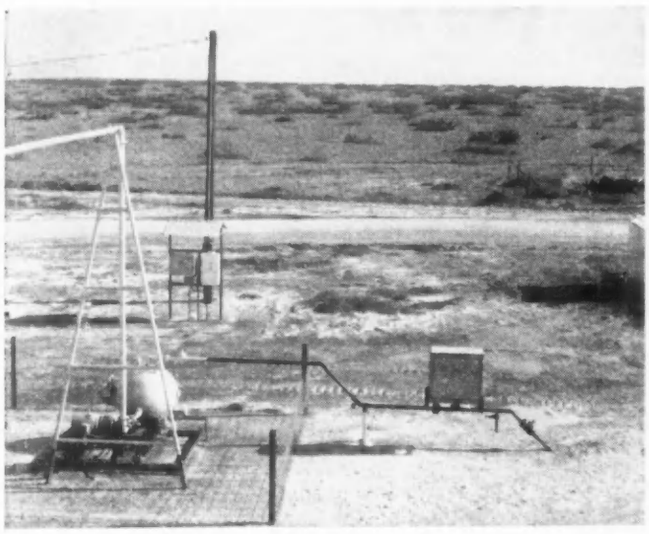


FIGURE 3—Vapor recovery unit on Phillips Donovan lease, used to recover rich hydrocarbon vapors, in Midland County, Texas. This lease is presently producing gas and distillate.

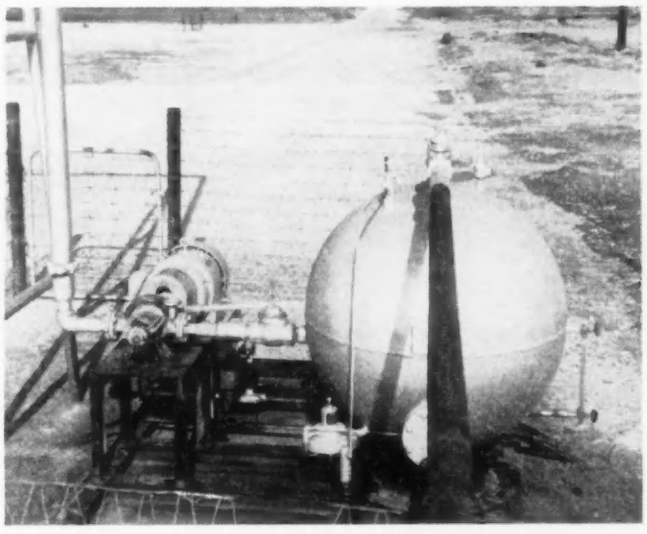


FIGURE 4—Close-up view of 10-horsepower, 50 Mcf per day capacity liquid seal compressor on Phillips Donovan lease connected to the Spraberry gasoline plant gathering system.

trapped into the fill line from the separator to the lease storage tanks. This arrangement has proved reasonably satisfactory although fouling in the liquid filter screen ahead of the compressor does require periodic attention to prevent frequent shut downs from overheating.

Apparently any type of fluid is satisfactory for the liquid seal. Salt water has been used and the second installation by Phillips uses 55 gravity produced distillate.

Due to the comparative inefficiency of the liquid seal compressors, Phillips plans to make trial installations in West Texas of positive displacement reciprocating or vane-type rotary units with appropriate safety controls. The company's production department now has 10 positive displacement reciprocating type units operating in the Four Corners area. However, for capacities exceeding 150 Mcf per day, it is planned to install the larger, slow-speed reciprocating units. The flexibility provided in these units for operating through a wide range of capacity and pressure demands by altering clearances possibly could result in standardizing on one make, size, and type for the majority of these larger installations. This, of course, will simplify both the operation and maintenance and reduce over-all costs.

The distinction made here between "high"-speed and "slow"-speed reciprocating units has been intentional. The small high-speed units, 600 rpm and over, only recently have been improved to provide a satisfactory unit for continuous, full-load operations. Improvements in lubrication and installation design to eliminate or reduce high-frequency vibration have made these units more acceptable for isolated field applications. Present installations in West Texas utilize an automatic liquid blow case on the inlet scrubber and many have bypasses between the discharge and suction to allow continuous operation. The latter, while reducing the frequent start-and-stop overloading on the electrical system, could result in excessive power costs in the event the unit is oversized. Phillips has tended to undersize the units in order to provide continuous full-load operation and reduce power waste.

TABLE 1—Income for Installation of Vapor Recovery Unit on the Phillips Petroleum Company-Donovan Lease-Spraberry Plant Gas Gathering System
Gas Volumes and Stock Tank Vapor Volumes

VOLUMES FROM METER ON STOCK TANK VAPOR LINE

Chart Dates	Time	Volume
10- 6-58 } 10-10-58 }	98 Hrs.	216.4 Mcf
10-10-58 } 10-16-58 }	112 Hrs.	237.7 Mcf
10-16-58 } 10-23-58 }	157 Hrs.	331.0 Mcf
Totals	367 Hrs.	785.1 Mcf = 2,140 cfh = 51.5 Mcf/day

(Total Chart Time 402 hrs.—Well down 10% of time)

PAYMENT FOR TEST CONTENT OF VAPORS RECOVERED BASED ON PHILLIPS CH-T FORM OF CONTRACT:

Premises:

1. Volume of stock tank vapors recovered ..... 46 Mcf/day
2. Test content of stock tank vapors ..... 6.80 gpm
3. Price per gallon of gasoline according to casinghead contract ..... 6.95¢ per gallon (Based on 36 gravity crude oil)
4. API gravity of raw gasoline (Use factor of 18.5% per Paragraph 7-A-3) .130°
5. Plant size factor (Between 30,000—40,000 test gallons) 30%

Payment:

(1) ¢/Mcf + (¢/Mcf x 1.30 / (Plant size factor)) + (Gravity or LPG payment ¢/Mcf / 6.95x6.80x18.5 %) = Total content payment per Mcf.

so, 15.60¢ + 4.68¢ + 8.74¢ = 29.02¢

(2) (Total content payment per Mcf) x (Vapor volume) = $/Day for test content of vapors.

so, 29.02¢ x 46 Mcf/D = $13.35

Compressor drives. The only driver utilized by Phillips has been the electric motor. Reduced operation and maintenance costs and the simple, inexpensive safety and control devices applicable to electrical controllers are attractive considerations. The installation of automatic batteries and the reduction in manpower in isolated lease locations make this a prime consideration in selecting driver units. Also, the relatively wide use of electricity on West Texas leases usually will provide both an adequate and economic source of power.

AN API FEATURE

Stock Tank Vapor Recovery

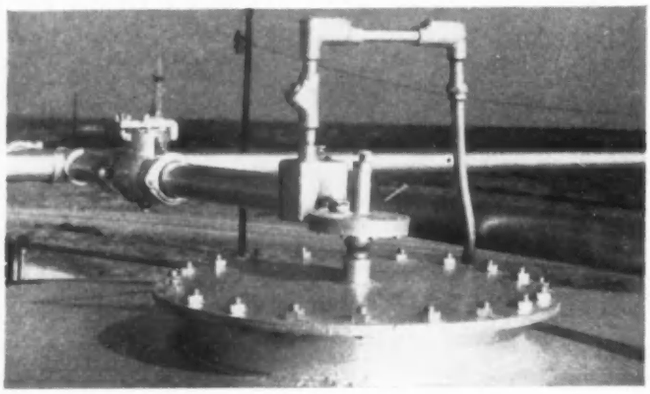


FIGURE 5—Typical switch, mounted atop 1,000-barrel crude oil storage tank, controls electric motor driven vapor recovery compressor.

The use of internal combustion engines certainly should be economical, particularly if sweet lease residue gas is available for fuel.

The efficient small gas turbine might have special applications. Phillips considered such a driver unit on one lease where multi-stage separation was installed. It was planned to take a sidestream of high-pressure gas through the turbine and exhaust it into the low-pressure gas system. A very brief and inconclusive survey of West Texas supply and manufacturing firms did not indicate such a turbine available at that time. However, in any future installation with similar lease operating conditions, it is planned to make a more extensive search for such a driver unit. If a small, 5 to 20 horsepower, efficient, compact unit is available, this would provide, in the writer's opinion, the ideal driver for rotary compressors. The word "efficient" is especially significant in these applications as there are usually several cents per 1,000 cubic feet differential paid between the high- and low-pressure gas. Therefore, a turbine-driven unit will have to obtain maximum horsepower conversion to justify its installation and operation.

About the Author

R. C. McCutchan, a native of Heavener, Okla., was graduated in 1938 from Colorado School of Mines with a degree of geological engineer. After brief employment with Magnolia Petroleum Company (Mobil), The Texas Company and U.S. Bureau of Mines Petroleum Experiment Station, he joined Phillips Petroleum Company in January, 1943. Since that time he has worked in all phases of the company's Natural Gasoline Department operations, including plant design, construction, operation and maintenance. He presently is working as staff assistant in the Western District office of the Natural Gasoline Department at Odessa, Texas.

The only control used in Phillips' installation is a direct-loaded diaphragm head operating micro switches to start and stop the motor driving the compressor. The company is attempting to operate in a range of 3 to 8 inches of water pressure on the crude storage tanks. The high-temperature and inlet scrubber high-level shutdowns are conventional mercury type switches connected to the electrical controllers.

Economics based on lease data. The over-all economics for these installations are based on the casinghead gas contract between producer and plant operator, which cover the leases from which the stock-tank vapors are recovered.

The data required to evaluate and write specifications for these installations consist of measuring the volume of stock-tank vapors and obtaining the hydrocarbon content. A standard orifice well tester is installed on the stock tank vapor line and the volume of vapors escaping are measured. With this record of volume, also the oil production during this period of measurement, a stock-tank vapor-produced crude oil ratio is established. This ratio then can be applied to normal lease production rates, taking into consideration allowable changes, future lease development and projected changes in surface operations.

It should be emphasized here that caution should be exercised and that these ratios cannot be applied indiscriminately. From tests it is known that not only reservoir conditions but surface operations, production rates, etc. apparently will vary the stock-tank vapor volume and the hydrocarbon content.

The hydrocarbon content of the vapors is obtained by the standard test car compression method. Once this information is available, the price paid to the producer is computed under the casinghead gas contract. Table 1 is an example of computing the price paid to the producer.

A test of 8.20 gallons per Mcf and a volume of 100 Mcf per day was measured on the Phillips-University Ellenburger lease. The testing of two other Ellenburger leases in this same general area, but from a different reservoir, tested respectively, 4.10 gallons per Mcf and 6 Mcf per day on one, and 3.40 gallons per Mcf and 9 Mcf per day on the other and provided very poor payouts. Therefore, it is imperative that thorough testing be conducted and the use of contents, ratios, and volumes between adjacent leases be judiciously applied.

Extra lease income. The continuation of the present trend of battery consolidation and lease automation will provide the necessary volumes and contents in most instances to make a profitable installation for the producer. This additional income, normally a total loss, becomes especially attractive in these times of reduced allowables, increasing costs, and shrinking profits.

In conclusion, it is believed the oil producer will find the gasoline-plant operator eager to cooperate in furnishing any reasonable test data required for evaluating these installations.

From "Practical Stock-Tank Vapor Recovery" by R. C. McCutchan, Phillips Petroleum Company, Odessa, Texas. Presented originally at Spring Meeting of the Southwestern District, Division of Production, Statler Hilton Hotel, March 2-4, 1960 in Dallas. —**The End**

AN API FEATURE

TURBODRILLING: WHAT IS ITS STATUS TODAY?

Although effective in limited applications, the turbodrill cannot compete economically with good rotary drilling practices

By W. E. Bingman, Drilling Engineer
Shell Oil Company, Midland, Texas

DURING 1958 AND 1959, an extensive field-test program was conducted in the United States of the Russian and French turbodrills to evaluate turbodrilling in competition with good rotary-drilling techniques. As a result, current turbodrilling methods and equipment, using both rock and diamond bits, have been adequately tested. It has been decided that, until such time as bit and equipment research development justifies a new program, there is little to be gained in further field testing.

The following conclusions were reached after extensive field testing of current turbodrilling methods and equipment, including both diamond bits and rock bits:

- Turbodrilling cannot, as yet, compete economically with good rotary practices. Where effective bit weight cannot be used with rotary (crooked hole, directional drilling, small hole size, and large surface hole drilling), turbodrilling eventually should prove competitive.

- Rock bits generally have performed poorly on the turbodrill. Penetration-rate improvements have not offset the drastic reduction in bit footage (often less than 30 percent that of rotary). The type of bit wear indicates that the cutting structure, as well as the bearings, will require modification for turbodrilling.

- A few economical turbodrill diamond bit runs have been made where the conditions were favorable. However, inconsistent turbodrill and bit performances have cancelled such savings on subsequent runs. More basic research should be conducted to determine the factors affecting diamond bit performance. Surprisingly, little is known about the effects of crown shape, waterway design, diamond size, quality, concentration and exposure, and drilling variables on the penetration rate and bit life.

- Turbodrills, as well as the bits, need modification before turbodrilling can be used effectively. Characteristics should be altered to provide optimum drilling conditions at the bit (subject to the findings from bit research). The tool also should be re-designed for field servicing and provided with a better shaft seal.

- A reliable turbine tachometer has been developed and field-tested satisfactorily below 12,000 feet.

- Current turbodrill equipment, bits and techniques have been adequately tested under our drilling and economic conditions. Before further field testing can be recommended, basic research in bit design (both rock bits and diamond bits) is needed, and significant modifications in the turbodrill should be made.

PERFORMANCE OF TURBODRILLING EQUIPMENT

Turbodrill. The mechanical performance of the turbodrill was quite reliable under selected conditions. However, the need for some design modifications was apparent rather early in the test program.

Several oil-resistant rubber materials were tested to provide thrust and radial bearings that would satisfy the drilling requirements in this country. Initially, some difficulty was experienced with the rubber-metal bond, but this problem was eventually solved. Life of the thrust bearings varied widely, however, depending upon the type of drilling fluid and load on the bearings. Some field tests showed that the life was over 200 hours under favorable conditions, but only 10 to 40 hours under

adverse conditions. The following factors contributed to premature thrust-bearing failures:

1. Oil having a low aniline point (below 160° F).
2. Mud containing abrasive solids (more than 1 percent sand).
3. High thrust-bearing loads when the hydraulic and bit loads could not be adequately balanced (± 5,000 pounds).

A more serious problem was presented by the lower radial bearing design, particularly when diamond bits were run on the turbodrill. There was a wide variation in the amount of fluid lost around the turbine shaft, depending upon the pressure differential across the lower radial bearing and the clearance. Lab tests showed that approximately 25 percent of the circulating volume was vented at the lower radial bearing when 250 psi pressure differential was imposed across a new bearing.

Partial plugging of a diamond bit, or any wear in the bearing, would drastically increase this loss of fluid above the bit. Besides hampering bottom-hole cleaning and bit performance, venting of fluid through the bearing has contributed to rubber bonding failures. In some cases, a high pressure differential has caused the rubber to be washed out between the housing and turbine shaft.

Several methods of sealing or restricting the flow through this bearing were tested, but with only limited success. An improved lower bearing seal is still needed before high pressure differentials can be tolerated across the bit. The development of an adequate seal should make the performance of the turbodrill and the bits, particularly diamond bits, more consistent.

Diamond bits tested. Many different diamond bit designs were field-tested on the turbodrill, in holes ranging in size from 5⅞ to 9-inch, in competition with rotary rock bit performances. Efforts were made to modify the tested designs to make them more compatible with the turbodrill.

One of the early attempts to provide a long running bit for the turbodrill was the use of a diamond core head with a core crusher sub mounted directly above it. The idea was to cut a core and then mechanically crush it with cone-type cutters. As was expected, high penetration rates were obtained. However, the crusher was ineffective when it became jammed with cuttings or when a segment of the core rotated with the assembly.

Some of the early "successes" resulted from runs of a spiral-pad diamond bit designed for turbodrilling in France. This bit, which was designed to impose a minimum back pressure on the lower radial bearing of the turbodrill, has very large spiral water courses that radiate from a deep concave center. Although a few bit runs were economical, the performance of this bit was erratic, as it fequently "ringed-out" after drilling short footage. The characteristic type of failure for this bit was very severe wear (or ringing out) on the crown with only very slight wear in the center. Apparently, fluid distribution was inadequate to prevent the buildup of solids around the diamonds, resulting in overheating in this critical area. Several modifications of this bit type were tested, but none of them eliminated the problem.

Another diamond bit also offered encouragement for turbodrilling. This bit, an individual waterway pattern, having a lower diamond carat weight, performed very well in medium-hard formations. Wear was excessive when hard formations (chert, quartzite, pyrite, etc.) were drilled, indicating that formation characteristics greatly influenced the bit performance. This design provided better cleaning and cooling of the bit crown, as localized overheating was not experienced. However, two other problems were presented by this design: (1) the pressure differential across the bit was higher, which caused some turbodrill trouble, and (2) the bit occasionally

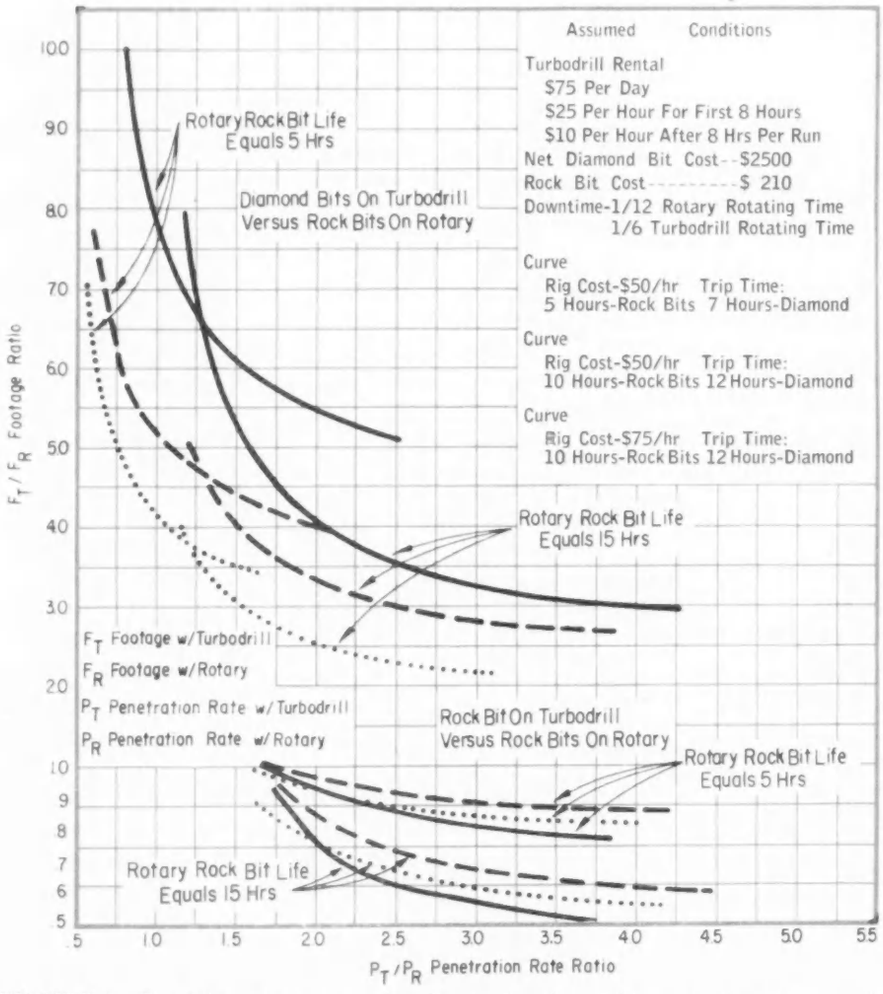


FIGURE 1—Breakdown cost curves for diamond and rock bits on turbodrill vs. rock bits on rotary.

plugged (⅝-inch diameter core hole and ejector port of the bit) when shale was encountered.

Several other diamond bit designs were tested in an effort to find a more versatile bit, but each showed weaknesses when the formations varied appreciably. Probably the most versatile diamond bit was one featuring a unique bi-center design. This bit is only 8⅝ inches in diameter, for example, but because of its eccentricity it will drill an 8⅞-inch hole. This presents an important advance in diamond bit design, since it permits running rock bits alternately without requiring reaming or reduction in hole size.

After turbodrilling with other diamond bit designs, it often was necessary to ream when rock bits were eventually run, but no difficulty was encountered following runs of the bi-center diamond bit. Several long runs have been made with this bit on the turbodrill. In fact, almost 500 feet were drilled through abrasive sandstone and limestone with one bit on one of the more recent turbodrill tests. Generally, the wear on this bit has been uniform, with no indication of localized overheating. However, in very hard formations, gage wear has been excessive.

Normally, penetration rates with diamond bits on the turbodrill have been about the same as those with rock bits on rotary for drilling sands and carbonates. However, when shale has been drilled, the penetration rates have been lower. This is partly caused by the light bit weights required for drilling shale stringers.

On most of the tests, bit weights were 5,000 to 15,000 pounds for 8 or 9-inch diamond bits on the turbodrill, while 25,000 to 30,000 pounds could have been used with the same diamond bit on rotary. Limited data showed that the penetration rate improved very little with high turbine speeds (800-900 rpm vs. 125 rpm for rotary) when there was such a difference in allowable bit weight. This suggests a possibility that turbine speed might be reduced, if torque could be increased without altering turbine efficiency.

Rock bit results. A lower turbine speed should prove far more important for the economic application of current rock-bit designs. In general, rock bits have performed very poorly on the turbodrill because of high rotational speeds. The basic problem is one of cutting efficiency. A rock bit may drill two or three times faster on the turbodrill than on rotary, but the rotational speeds are probably more than eight times faster. Consequently, less bit footage is obtained due to higher rates of bearing and tooth wear per foot of hole drilled. The relations between the two types of wear is dependent upon the bit size and loading.

Both conventional and modified rock bits have been run in a variety of drilling fluids, including water, low-solids oil-emulsion, low-solids fluid containing extreme pressure lubricant, salt-water oil-emulsion, and native muds. These tests have clearly shown that turbodrill runs with "off-the-shelf" rock bits cannot ordinarily compete with good rotary performances, regardless of the fluid properties. In fact, only one successful application was found using currently available bits. Turbodrilling was economical for drilling large-diameter surface holes (in hard formations with unrestricted bit weight), where rotary performance was poor because of drill-pipe "twist-offs." (Gas storage project near Herscher, Ill., for Natural gas Storage Company of Illinois.)

Tests of modified rock bits having journal bearings, fluid ports to the bearings, larger-than-standard bearings, altered tooth patterns, hard facing on the teeth and shirt tails, recessed ball plugs, reduced cone offset, and changes in cone angle have shown that such modifications are insufficient to broaden the application of rock bits. Sealed-bearing bits have more promise; however, the over-all economics would probably be only slightly affected, since rotary performance also should be improved.

Undoubtedly, extensive research effort will be required to develop a high speed rock bit. Turbodrilling might compete economically with rotary much sooner if turbine characteristics were altered to fit the upper limits of rotary rock-bit capabilities.

Instrumentation aided tests. Turbodrill testing was aided by the use of two instruments: a turbine tachometer and flow meter. The tachometer made it possible to operate the turbodrill at maximum horsepower, resulting in higher penetration rates. Bit weight was adjusted to control the turbine speed such that maximum horsepower was developed. The tachometer was even more important as an aid in the selection of optimum bit weight during reaming operations.

Since the characteristics of the turbodrill are greatly affected by the circulation rate (speed varies proportionally—torque as the square, and horsepower as the cube), an accurate knowledge of any variation in circulation rate is desirable. The use of a magnetic flow meter proved very satisfactory for this purpose.

Two tachometer designs, one hydraulic and the other mechanical, were tested during the turbodrill test program. Both units are mud pulse generators which are driven by the turbine shaft. The hydraulic unit uses a rotary positive-displacement pump to actuate a dart-type valve in the mud stream. The mechanical one utilizes a cam mechanism to control the pulse valve. Pressure pulses are transmitted by the mud stream and are detected by a sensitive pressure-electrical transducer located at the standpipe. Each pulse, which represents a given number of turbine shaft revolutions, is recorded on a time chart for mathematical conversion to turbine speed. For example, if each pulse represents 200 revolutions of the turbine shaft, four pulses per minute (15 seconds between pulses) would indicate a turbine speed of 800 rpm.

This method of determining turbine speed has been quite reliable, even to depths below 12,000 feet. Other methods have been attempted in Russia without success, except at very shallow depths. With the development of appropriate equipment, it should be possible to transmit the turbodrill data (bit weight, hole deviation and direction, etc.) in this manner because of the availability of a down-hole power source.

Another instrument, a magnetic flow meter, proved helpful when the volumetric efficiency of the pump was in question. This equipment performed satisfactorily, even though properties of the mud vary appreciably from one test to another. The flow meter is not considered essential for routine turbodrilling. However, it does offer a substantial contribution to field test data.

U.S., RUSSIAN ECONOMICS DIFFER

In Russia, where a limited number of drilling rigs is available and a great number of wells must be drilled

each year, a premium price can be paid for increasing the yearly footage drilled by each rig. Russians report turbodrilling has improved their drilling performance by increasing the penetration rates and by reducing the number of fishing jobs as a result of lower drill-pipe torque.

In our drilling economy, however, a bonus cannot be paid for increasing the drilling rate. Turbodrilling must compete—as any other drilling technique—on a cost-per-foot basis, since rotary techniques have been developed sufficiently to meet present drilling requirements in this country. Therefore, identical turbodrill performance could be considered commercially successful in one economy and unsuccessful in another. Increased penetration rates normally are obtained with the turbodrill. However, the over-all drilling rate and economics are influenced by other factors that have proved more important.

Turbodrilling may be considered as a modification of conventional rotary techniques, in which much of the hydraulic horsepower is converted to mechanical horsepower at the bottom of the hole. The hydraulic characteristics of the turbodrill cause very high bit-rotational speeds (approaching 1,000 rpm), resulting in higher horsepower at the bit than are obtained with rotary. Since the surface equipment and operational techniques between the two methods are quite similar, the relative economics of rotary and turbodrilling can be compared readily.

TABLE 1—Illustration for Using Breakeven Cost Curves

ASSUMED CONDITIONS
Turbodrill Rental:
$75 per day; $25 per hour for first 8 hours; $10 per hour after 8 hours per run.
Net Diamond Bit Cost—$2,500
Rock Bit Cost — 210 ($8\frac{3}{4}$")
Downtime:
Rotary—2 hours every 24 rotating hours.
Turbodrill—4 hours every 24 rotating hours.
Turbodrill Trip Time (compared with rotary)—Same with rock bits but 2 hours longer with diamond bits.

Rotary Rock Bit Experience	Turbodrill Performance Required To Preakeven
Example A Penetration Rate 9 ft/hr Bit Life 5 hrs Bit Footage 45 ft Trip Time 10 hrs Rig Cost $50/hr	**Example A** For Rock Bits: 41 ft/bit @ 22.5 ft/hr or 38 ft/bit @ 36 ft/hr For Diamond Bits: 293 ft/bit @ 6.75 ft/hr or 236 ft/bit @ 9 ft/hr
Example B Penetration Rate 3 ft/hr Bit Life 15 hrs Bit Footage 45 ft Trip Time 10 hrs Rig Cost $50/hr	**Example B** For Rock Bits: 33 ft/bit @ 7.5 ft/hr or 27 ft/bit @ 12 ft/hr For Diamond Bits: 225 ft/bit @ 3.75 ft/hr or 150 ft/bit @ 6 ft/hr
Example C Same as Example "A" except Rig Cost—$75/hr	**Example C** For Rock Bits: 38 ft/bit @ 22.5 ft/hr or 36 ft/bit @ 36 ft/hr For Diamond Bits: 230 ft/bit @ 6.75 ft/hr or 185 ft/bit @ 9 ft/hr
Example D Same as Example "B" except Rig Cost—$75/hr	**Example D** For Rock Bits: 29 ft/bit @ 7.5 ft/hr or 25 ft/bit @ 12 ft/hr For Diamond Bits: 167 ft/bit @ 3.75 ft/hr or 113 ft/bit @ 6 ft/hr
Example E Same as Example "A" except shallower depth where Trip Time—5 hrs	**Example E** For Rock Bits: 38 ft/bit @ 22.5 ft/hr or 34 ft/bit @ 36 ft/hr For Diamond Bits: 500 ft/bit @ 6.75 ft/hr or 360 ft/bit @ 9 ft/hr
Example F Same as Example "B" except shallower depth where Trip Time—5 hrs	**Example F** For Rock Bits: 28 ft/bit @ 7.5 ft/hr or 22 ft/bit @ 12 ft/hr For Diamond Bits: 325 ft/bit @ 3.75 ft/hr or 180 ft/bit @ 6 ft/hr

Downtime greater. Although fewer drill collars (requiring less handling time) are used with the turbodrill, trip time normally is somewhat longer (about the same time with rock bits but two hours longer with diamond bits). Additional time is required for checking the turbodrill thrust bearing wear, laying down one tool, picking up another, and washing or reaming to bottom. Downtime, also, is significantly greater with the turbodrill. For rotary, an average of two hours per day might be spent for routine maintenance; whereas normally twice that amount of downtime, is required for turbodrilling (mainly pump maintenance). Higher rig operating costs would be expected from higher pump-maintenance costs, but corresponding cost reductions should be obtained with lighter weight drill pipe and less drill collar maintenance.

Therefore, with rock bits, turbodrilling penetration rates must be high enough to compensate for more downtime, less bit footage, and higher rig operating cost resulting from turbodrill rental. On the other hand, with diamond bits, turbodrilling footage must be long enough to compensate for more downtime, more round-trip time, higher net bit cost, and higher rig operating cost (from turbodrill rental). The effects of factors influencing turbodrill economics are shown by the "break-even" cost curves in Figure 1 and by the illustration in Table 1. These examples show that the economics of turbodrill-rock bit operation are improved by higher rig operating costs and shallower depths, whereas the economics of turbodrilling with diamond bits are improved by higher rig operating costs and greater depths.

Since turbodrilling penetration rates with rock bits seldom have exceeded three times that of rotary, the importance of obtaining more than 60 percent bit footage is apparent from the curves. With bit life less than three hours (except in very soft formations) on the turbodrill, a very substantial increase in penetration rate is required to maintain such footage ratio. Therefore, before turbodrilling with rock bits can compete with good rotary performance, some method must be devised for increasing rock bit life to 5 or 6 hours.

Turbodrilling economics with rock bits are best (although still uneconomical with currently available equipment) where:

Well depth is shallow
Hole size is large
Rotary performance is poor
Rig operating cost is high
Formations are medium-hard to hard (non-abrasive)
Rig hydraulics are adequate
Pump downtime is not excessive and
The drilling fluid is conducive to long turbine life.

More definite criteria can be established only after improvements in bits and equipment make turbodrilling more competitive.

The potential for turbodrilling with diamond bits has been illustrated by several very good economical runs. However, the performance has been too inconsistent to be economical. Based on the better performances, assuming diamond bit and turbodrill modifications would

eliminate the premature bit failures, the following criteria should offer the best applications for turbodrilling when:

1. The formations are conducive to rotary diamond bit drilling, such as sandstones, limestones, and dolomites (avoid chert, quartzite, and soft shale).
2. The mud has a minimum amount of lost circulation material; contains low abrasive solids (above 1 percent sand); has a low aniline point oil (160° F or below); and temperatures below 180° F.
3. Rig hydraulics are adequate and the pumps can be operated at rated loads without excessive downtime.
4. Rig operating cost is high (exceeds $50 per hour).
5. Rotary trip time is long (exceeds five hours).
6. Rotary rock bits drill short footages (less than 70 feet).
7. Rotary penetration rate is low (less than 7 feet per hour).
8. Rotary rock bit life is less than 15 hours.
9. Hole size is 9 inches or less

Satisfactory penetration rates have been obtained in formations that were suitable for diamond bit drilling. However, the footage was frequently too low for economical operation. The break-even cost curves and illustration Figure 1 and Table 1—define the necessary footage and penetration rates for equal turbodrilling and rotary costs. It is apparent from these curves that a moderate increase in penetration rate (in the 0.75 to 1.5 ratio range) would reduce drastically the required diamond bit footage for break-even costs. Possibly such an improvement could be obtained by better diamond bit cleaning and higher bit weights, which would require correspondingly higher turbine torques.

RECOMMENDED DEVELOPMENT EFFORTS

Development of suitable downhole equipment should be encouraged because of the trend toward deeper drilling and more directional work. Since currently available turbodrills, bits and accessory equipment do not provide an adequate combination for commercial operation, development efforts should be redirected toward a more basic approach.

The principal problem that prevented turbodrilling success was poor bit performance. However, the turbodrill characteristics and limitations are believed to have contributed greatly to this problem. An earlier application for this technique might be obtained by designing a down-hole tool to fit current bit designs, rather than designing a radically new bit.

Improvements needed. A tool should be designed to approach the upper speed limit of rock bit endurance (for 5 or 6 hours bit life) without causing a drastic reduction in cutting efficiency (penetration per revolution). The field tests of the turbodrill have shown that present turbine speeds are too high for rock bits and the torque is too low for diamond bits (need to run more bit weight). This suggests that a tool having higher torque and lower speed (perhaps the same horsepower) should perform better with both diamond bits and rock bits than present turbodrills. A few mechanical improvements also should be incorporated into the new tool, such as better turbine shaft seal, re-location of the thrust bearings for field servicing, etc.

The development of a suitable rock bit for the turbodrill probably will require considerable time and effort. In addition to the bearing problem, which is currently receiving much of the designer's attention, there also is the problem of modifying the cutting structure to improve the cutting efficiency at high speeds.

Certainly the bearing problem is eliminated in the diamond bit. However, many basic factors influencing diamond bit performance must be determined before this type of bit can be used economically on the turbodrill. The need for more basic diamond bit research is apparent from the fact that even the manufacturers are not in agreement on basic design considerations, such as:

- What is the best shape for the bit crown? (Flat bottom, convex-concave, sharp crown with deep concave center, rounded crown with shallow concave center, etc.)
- What determines the best diamond size, quality, exposure, and concentration? (Formation hardness, unit loading, work per stone, linear speed, etc.)
- What determines the best waterway design? (Pressure drop per inch of bit diameter, circulating volume per inch of bit diameter, bit hydraulic horsepower, waterway proximity of each stone, etc.)

Since the answers to these questions have not been found, the reason for the infinite variety of diamond bit designs is apparent. As a result of this unlimited variation in design, field testing alone cannot adequately isolate the factors affecting diamond bit performance. When the design criteria have been established and the optimum drilling conditions also have been determined, a drilling tool then can be designed to provide the right conditions at the bit.

This article is based on a paper titled "Status of Turbodrilling in the U.S.A." presented at the API Spring Meeting of the Southwestern District, Division of Production, Dallas, March 3-4, 1960.

About the Author

W. E. Bingman was graduated in 1951 from University of Illinois with a B.S. in mechanical engineering. He joined Shell Oil Company and, following a one-year training program, he spent five years in the division office at Odessa, Texas, doing mechanical and drilling engineering work. He then was transferred to the Midland area offices as drilling engineer. For two of the past three years he has worked as project engineer on a company-wide turbodrill test program.

ACKNOWLEDGMENT

The author expresses his appreciation to the management of Shell Oil Company for permission to present this paper, which outlines the principal results of a Shell-Dresser cooperative turbodrill testing program. Appreciation is also extended to Dresser Industries who agreed to the publishing of the results of this testing.

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AN API FEATURE

IN THE MID-CONTINENT

SUCKER ROD FAILURES CUT 56 PERCENT IN 6 YEARS

Four-pronged study on corrosion, rod box make-up, well loads and selection of steels, shows rapid payout

By O. C. Atkinson, Division Engineer
Cities Service Oil Company, Great Bend, Kans.

A 56 PERCENT REDUCTION in sucker rod failures over a period of six years has been accomplished by Cities Service Oil Company in approximately 1,200 of its West Kansas wells. Rod breaks were reduced from 1,790 in 1953 to an estimated 789 breaks in 1959, and the downward trend in failures still is continuing. High water cuts, averaging 90 percent, with corresponding high volumes of fluid to be lifted, combined with severe corrosive conditions caused the company to attack the over-all problem simultaneously from four different fronts. This four-point program included:

- Corrosion inhibition, using the best inhibitors available, and adopting the "copper ion exchange" method of evaluating inhibitors in well fluids.
- Proper make-up and handling of rod strings, with emphasis on cleaning box and pin threads and snapping up tightly.
- Using dynamometer data to limit rod loads to values within the stress limitation of the particular rods used.
- Conducting mixed rod string tests to determine merits of various steels in corrosive Arbuckle waters.

West Kansas is noted for its corrosive waters and high water cuts, averaging 90 percent in the some 1,200 wells operated by Cities Service in the area. Many wells produce 98 to 99 percent water. Principal water-producing formations are the Arbuckle, Gorham, Reagan and Viola, all of which are more than slightly corrosive.

Rod failures reduced. Initially, water production in West Kansas was not much of a problem. As water cuts increased, pump sizes also were increased to maintain oil production and little attention was paid to the added stresses imposed on the sucker rod string. Also, little was known about corrosion inhibition.

Consequently, the added stresses, plus the effects of corrosion, soon caused sucker rod failures. Figure 1 shows how sucker rod breaks increased as water percentages increased.

From 1946 to 1953, water cut increased from 59.5 percent to 85.8 percent while rod breaks increased from 716 to 1,788 per year. Since 1953, water cuts have further increased and now average 90 percent. However, sucker rod parts have decreased to 942 in 1958, and, based on 10 months experience, were estimated at 789 in 1959. This is a reduction of 56 percent in six years.

The number of wells operated can be a big factor in the number of rod breaks experienced. Figure 2 shows the correlation between number of wells and number of rod breaks by years. In 1946 there were 793 wells operating and there were 716 breaks. By 1953 the number of wells had increased to 1,175 and the rod parts numbered 1,788. Since 1953 the number of wells operated has remained fairly constant at the latter figure while the rod parts have decreased.

Figure 3 shows the rod-break frequency in breaks per well per year. In 1946 the frequency was 0.904. This increased to 1.520 in 1953 and now has decreased to an estimated frequency of 0.677 in 1959.

PROGRAM

This reduction in sucker rod breaks has been brought about by the following four-point program.

Corrosion inhibition. It early was recognized that corrosion was a major factor in sucker rod failures. Little was known about inhibition at that time, and various attempts at using caustic, and inhibitors of the company's

own manufacture were of little avail. Consequently, progress was slow initially. Figure 4 shows the number of wells inhibited, by years. In 1946 only 86 wells were being treated. This increased slowly until, in 1952, 330 wells were being treated. In 1953, another 103 were placed on treatment. Presently, 592 are being treated.

Cities Service corrosion engineers have adopted the "copper ion exchange" test to evaluate inhibitors in well fluids. This test reduces trial-and-error methods used for so long, and gives a quick method of determining which inhibitor should be used.

After selecting an inhibitor the well is placed on treatment, usually by circulating five gallons of the inhibitor for a period of 24 hours. Then, at weekly or semi-weekly intervals, the regular dosage is circulated from two to four or five hours, depending upon the amount of fluid the well produces. The wellheads are closed in so oxygen is not drawn into the casing as the well is circulated.

Currently, 12 different chemicals are being used, nearly all of which have been selected on the basis of the copper ion test.

Box-and-pin makeup. Significant reductions have been made in sucker rod coupling breaks. Normally box-and-pin breaks can be attributed to hammering of the boxes, poor make-up, or corrosive fluid left inside the coupling. With the hydrogen sulfide corrosion present in West Kansas, it has been found that unless couplings are made up sufficiently to preload the pin, so shoulders do not separate under stress, corrosive well fluids will enter the coupling and be trapped.

Many of the broken boxes examined had deep internal pits. The corrosive water inside the coupling forms iron sulfide in the threads, making it difficult either to make up the joint or to break it out. If the joint is difficult

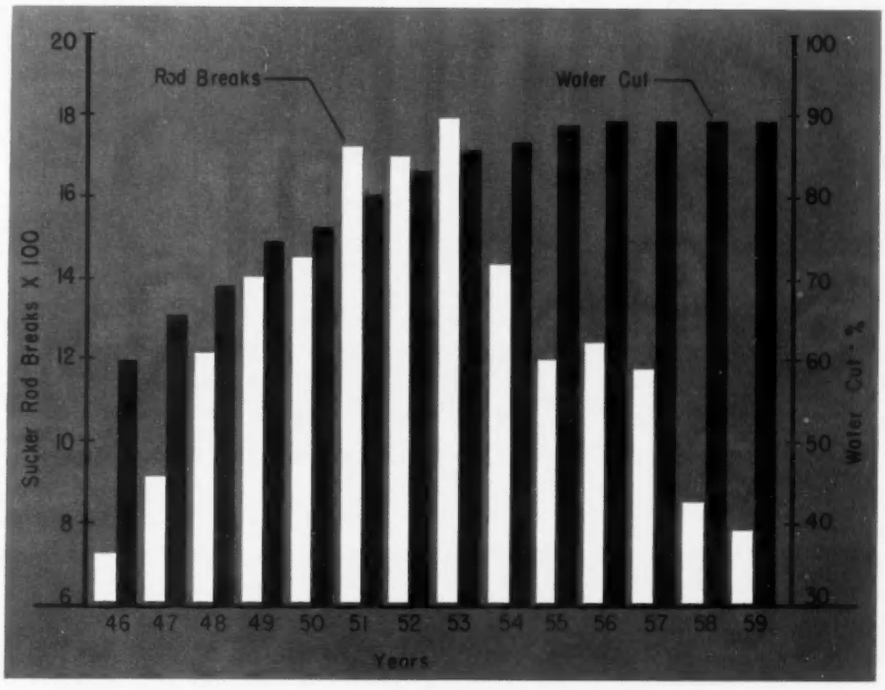

FIGURE 1—Sucker rod breaks related to water cut. Note that breaks increased as water cut increased up until 1953 when rod failures began sharp decline.

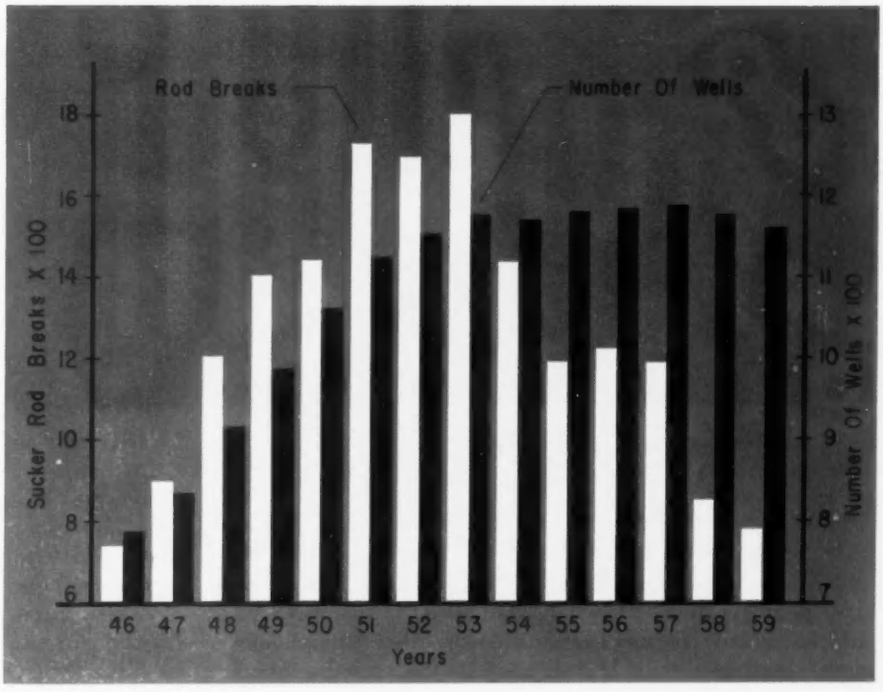

FIGURE 2—Correlation between number of wells and number of rod breaks. Rod failures have declined rapidly since 1953, while number of wells remained fairly constant.

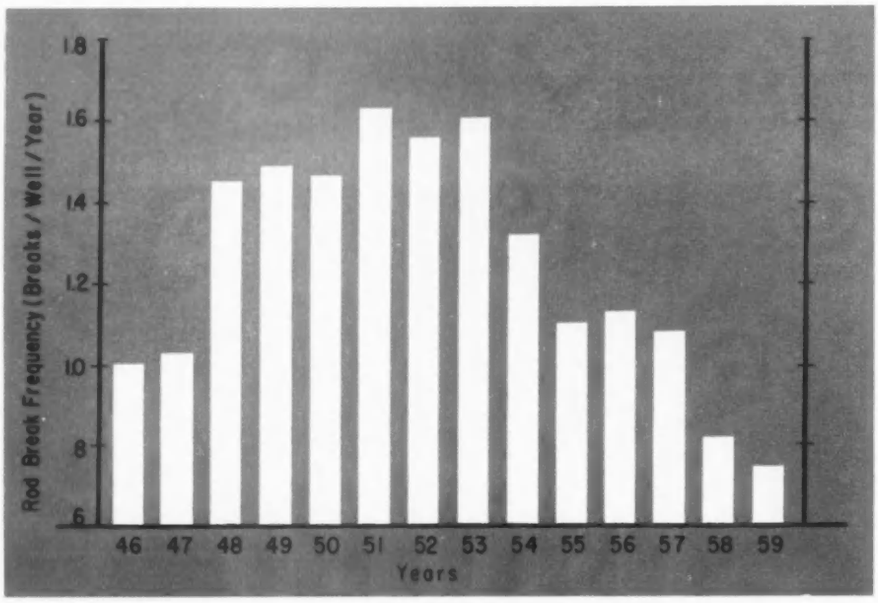

FIGURE 3—Rod-break frequency in breaks per well per year. Note that frequency curve still is on the decline.

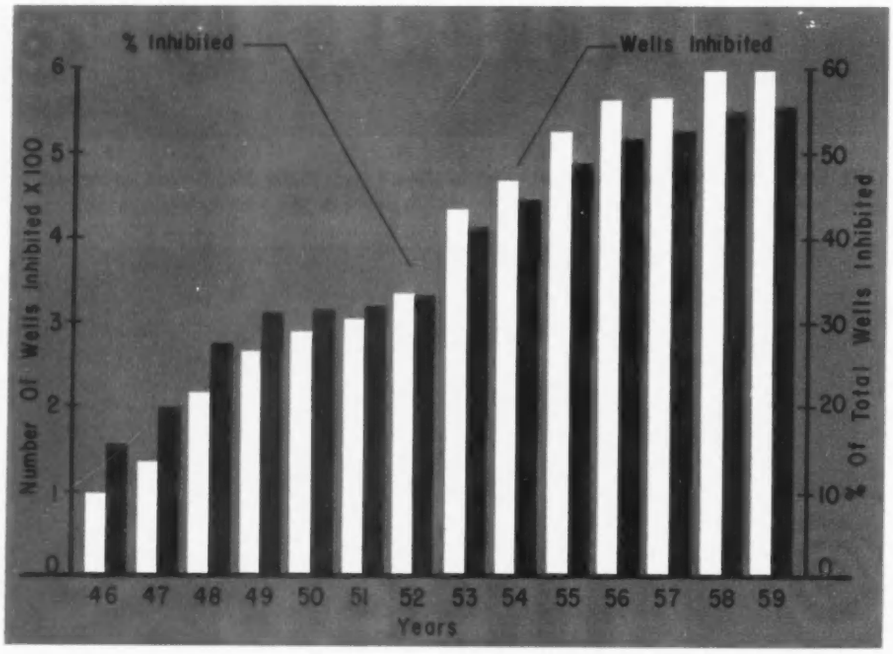

FIGURE 4—Number of wells inhibited, by years. Total wells under treatment now number 592.

to make up, the crews many times will fail to snap it up tightly, thus allowing more well fluids to enter.

A point is reached when the joint will not break readily because of the iron sulfide or other foreign elements, such as dirt, in the threads, so the crew hammers it. If the coupling is case-hardened, this does irreparable damage by cracking the case hardening and creating an entry point for corrosion.

Another effect of poor make-up is that when the shoulders separate, stress is imposed upon the last-engaged thread on the pin, causing early failure at that point.

Since hammering cannot be completely eliminated, the company has stopped buying case-hardened couplings. Also, when a well has excessive box-and-pin failures, rods are laid down in singles, the couplings removed, and threads are cleaned thoroughly with kerosine and wire brushes.

Thread chasers are run over the threads and the boxes are dipped in whatever inhibitor is in use at that well. The rods then are run back and made up with 36-inch snap wrenches. At this time, badly worn or badly corroded boxes are replaced. On a group of 16 wells, where this was done, the boxes replaced cost $953.60. The reduction in joint failures on these wells during the first year saved $3,367.60. This practice rapidly is being expanded.

Dynamometer studies aid. Since corrosion inhibition is not 100 percent effective, an attempt is made to operate wells so that damaging effects of corrosion are kept to a minimum. This is the job of the dynamometer man. In an inhibited well producing corrosive fluids, it has been found that the maximum desirable stress for sucker rods is about 20,000 psi. An attempt is made to limit loads to that figure by proper dynamic operations.

The wells are operated at non-synchronous pumping speeds.[1] Many times a well may be speeded up a stroke or two and actually reduce the peak loading by going from a synchronous to a non-synchronous speed.

An attempt is made to use the smallest-bore pump that will produce the desired amount of fluid. This prevents unnecessary loading of the rod string and tends to reduce the fluid pound so often found in small volume producers.

Where large-bore pumps are necessary to produce the desired amount of fluid, sucker rod strings are tapered to keep the stress at about 20,000 psi. The strings are tapered so kinetic energies are equalized in the sections of the string in preference to equalizing the static stresses at the top of each section.[2]

Counterbalancing is quite important in the life of sucker rods.[2] A well which is out of balance can cause undue stresses in the upper portion of the string and may cause buckling in the lower portion. An attempt is made to keep wells properly counterbalanced.

Rod steels tested. The most commonly used sucker rod steels in West Kansas are the 1036, or carbon manganese, and the 4600 series, or nickel-moly. As sucker rod failures increased, Cities Service started buying more and more of the 4600 steel for use in the corrosive wells, in the belief that with the addition of nickel the rods would be more resistant to corrosion attack.

There was much discussion as to whether the so-called corrosion-resistant steels were of any advantage, or at least enough better to justify the increased cost of the rods. In April 1955, the company embarked on a series of mixed-string tests to determine as accurately as possible the merits of the various steels in corrosive Kansas Arbuckle wells. Tests were conducted under actual field operating conditions, using the best inhibition practices known.

The tests were designed to test two or more types of steel.[3] In other words a test string would be composed of 1036 steel, 4600 series steel and/or a special steel.

The rods were placed in the well alternately by steels or by makes so that one rod would not be favored over another. They were purchased out of stock at the various supply stores. The tests were to run for a two-year period or until failures in any particular test string became excessive.

Since the vast majority of the rod failures experienced in West Kansas are in large-volume Arbuckle wells, all test wells were chosen from that category.

All rods were marked with an identifying number on the wrench square according to a schedule sent to the field. Thus, the make, grade, and location of any rod in the string could be identified.

The rods were handled in a normal manner. No special handling was given them in any respect. An engineer was present at each test-string installation to make sure the rods were installed as planned.

All test wells were operated at non-synchronous speeds which is the company's usual practice. Test wells were operated at or near 20,000 psi maximum stress, except in special cases where the tests were 1036 steel vs. the so-called high-tensile-strength rods. These special cases were operated at or near 26,000 psi maximum stress.

All test wells were treated with the best inhibitor available for that particular well. All were operated in accordance with good operating practice. To maintain wells within the limits set for each test, each was weighed every six months and the data recorded.

Each rod part was replaced with a new rod of the same make and grade of steel and in the same location from which the parted rod was removed. Each parted rod was sampled by cutting off sections of the rod from each side of the part and the numbered end. These were bound together, tagged with the necessary identifying information and sent to the division office. Many of the samples were later picked up by the various manufacturers for study.

Sucker rods made by seven different manufacturers were represented in these tests. Rods of 1036-type steel and 4600-type steel were tested for each of the seven manufacturers. In addition, four special-type rods were tested.

In the 22 tests completed, 3,012 rods were tested. Table 1 shows the performance of the three classes of steels tested.

TABLE 1—Comparisons of Steels Tested

STEEL TYPE	Number of Rods	Percent of Rods	Number of Breaks	Breaks Per 100 Rods
1036	1,141	37.88	28	2.45
4600	1,456	48.34	91	6.17
Special	415	13.78	55	13.99
Total	3,012	100.00	174	5.78

Test results. Table 1 shows that 1036 steel was more satisfactory in West Kansas Arbuckle production under the test conditions.

Although the tests were not intended to compare manufacturers, it was apparent that there were differences in performance of the same type of steel obtained from different manufacturers. Considering the fact that the chemical and physical specifications for a particular steel are pretty well fixed, it can only be concluded that manufacturing processes can influence the quality of the sucker rod.

As a result of these tests, Cities Service is buying only 1036 steel sucker rods for its West Kansas operations. It is expected that sucker rod expenditures will be reuced by $10,000 per year; also that sucker rod failures will be further reduced.

From a paper entitled "A Program to Reduce Sucker-Rod Failures—West Kansas Operations," O. C. Atkinson, Cities Service Oil Company, presented at Mid-Continent District Spring Meeting of API, Production Division, March 30-April 1, 1960, Wichita, Kan.

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About the Author

O. C. Atkinson received his B.S. degree from Oklahoma A. & M. (now Oklahoma State University) School of Engineering in 1936. Joining Cities Service Oil Company (then Empire Oil & Refining Co.), he was made district engineer in 1939, working in the North Texas-South Oklahoma area. In 1945 he became special engineer, working as mud engineer, in the West Edmond and Lindsay fields. He was promoted to assistant district superintendent in 1949, with headquarters at Graham, Texas, and, in 1952, was sent to Vernal, Utah, on wildcat drilling work. He was made assistant division engineer of the West Kansas Division in 1953 and, in the fall of that year, was made division engineer, the position he still holds.

AN API FEATURE

NEW TEST TOOL SAMPLES SEVERAL ZONES IN ONE TRIP

Multiple zone testing tool yields fluid samples, pressures and other reservoir data

By Pat Chisholm, Engineer
Tool Development Section, Halliburton Oil Well Cementing Co.
Duncan, Okla.

A RECENTLY DEVELOPED formation testing tool now makes it possible to obtain formation fluid samples and closed-in pressures from several zones, or sections of a single zone, with but one trip of the drill pipe. It consists of two assemblies: the packer group which is run on the drill pipe and the sampler which is run on a wire line and which can be retrieved for each test. The sampler contains two pressure recorders, an inside chamber recorder and an outside blanked-off recorder. Samples of formation fluid, up to 25 gallons or more, can be taken from test intervals ranging from 1 foot to 12 feet.

Potential uses of the new formation evaluation tool, where several tests are desirable, will be in:

- Making multiple formation tests in exploratory wells
- Checking productivity of various beds or stringers within a thick producing section
- Determining the oil-water cut
- Making hydrodynamic studies.

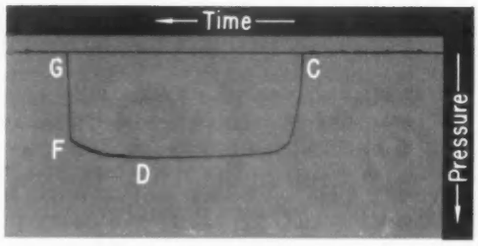
Two techniques presently are used in formation evaluation. One involves running a packer and other tools on drill pipe; the other is run on wire line. The advantages and limitations of both are well known.

The multiple-zone sampler was developed as a combination of the two methods. Its aim is to incorporate advantages of both methods into one tool. Two packers, with a perforated spacer between them, are run on drill pipe to the test point and set.

A sampler then is run inside the drill pipe and landed on a seat connected to the perforated spacer as shown in Figure 2. This arrangement permits withdrawal of sizable samples and the recording of pressures from several zones by removing the sampler each time by wire line. The drill pipe need not be removed from the hole since it is only necessary to change the packer location between each run. This saves rig time where several tests are to be made.

DESCRIPTION OF EQUIPMENT

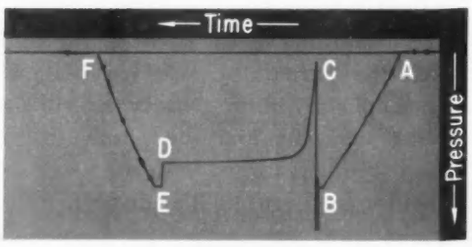
Tools run on drill pipe. Conventional open-hole testing tools are run on drill pipe. Starting from the bottom, a side-wall anchor, straddle packers, safety joint, hydraulic jar, and stabbing joint are made up. Two concentric tubes



INSIDE CHART

A-B	Running Sampler in Hole
B	Initial Hydrostatic Mud Press.
C	Tester Valve Opened
C-D	Formation Build-Up
D	Tester Valve Closed
E	Final Hydrostatic Pressure
E-F	Retrieving Sampler
F-G	Releasing Press. at Surface

FIGURE 1



BLANKED OFF CHART

are made up inside a perforated joint between the packers.

On the upper end is a seal seat which receives the sampler. The outside tube is connected to the perforated joint and provides a flow passage during the test. The smaller tube is connected to a separate set of perforations so there is no communication between it and the flow tube. When the sampler is seated, this tube seals into the blanked-off gage case.

The packer arrangement has four ½-inch fluid-bypass ports between the packers and four ¾-inch ports above the top packer. These ports help provide fluid communication inside and outside the drill pipe, and above and below the packers at all times. This reduces the possibility of the well getting out of control. It also permits circulation when necessary.

Sampler assembly. The maximum diameter of the sampler assembly is 2.38 inches. It is equipped with a pressure-relief valve, sample chamber, tester valves, and two pressure recorders. Centralizers are used at the top and on the lower portion of the sampler to guide its passage through drill pipe and reduce lateral shock.

The function of the relief valve is to allow the chamber pressure to be bled off manually at the surface. It is a pressure-balanced, O-ring sealed, sliding valve.

Chamber volume is determined by the number of sample barrels run. Each barrel is 7 feet long and has 0.9-gallon capacity.

The testing valve is an O-ring sealed sliding type with a built-in bypass. It is opened when the sampler seats. A protective shield is used to help prevent premature opening, such as by striking a shoulder or obstruction in the drill pipe.

The valve is pressure-balanced, except when in the open position. In this position, hydrostatic mud pressure exerted over a differential area in the valve tends to hold the sampler sealed on the seal seat until after the test valve has closed and the bypass port has opened.

Pressure recorded. The sampler contains two 1¼-inch OD bourdon tube pressure recorders, one in the sample chamber and one outside. The inside recorder shows chamber pressure only. The other, a blanked-off recorder, is positioned below the testing valve (see Figure 1). It records hydrostatic mud pressure as the sampler is lowered inside the drill pipe (A-B), pressure changes in the test interval during the sampling period independent of fluid flow (C-D), final hydrostatic pressure of the mud column (E), and returning out of the hole (E-F). The blanked-off pressure recorder is desirable, since it helps determine the validity of a test.

The interval between packers is variable and may be

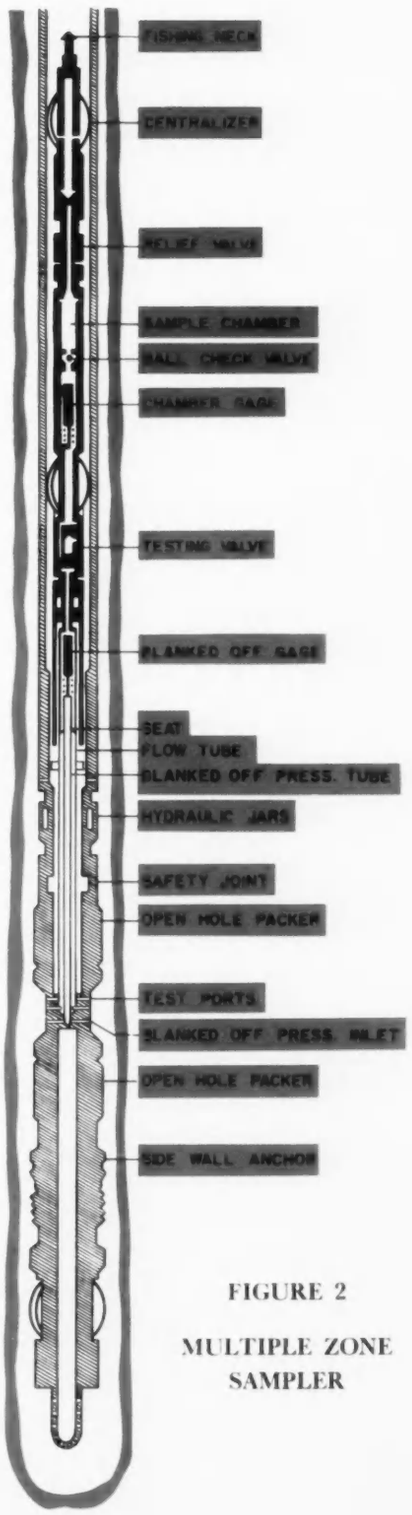


FIGURE 2

MULTIPLE ZONE SAMPLER

AN API FEATURE

New Formation Sampler

Most of the components used are standard equipment. Only minor adaptions were necessary

as little as 1 foot. The interval to be used on a particular job will be determined by the average sand thicknesses and nature of information desired. In a case where fluid samples are important, the smaller the test interval in relation to sampler capacity, the more representative the sample. Where pressures are more important, sample volumes may be adjusted to yield a maximum amount of pressure data regardless of interval.

Surface equipment. Surface equipment required for this type operation consists of: (1) wireline unit; (2) lubricator and oil saver or line wiper; (3) surface gage to check chamber pressure before venting; and (4) surface control valve.

DEVELOPMENT OF EQUIPMENT

Most of the components used in this arrangement are standard equipment presently used in the field. Only minor adaptations were necessary. Only a suitable sampler and seating arrangement had to be provided.

Field tests. Preliminary laboratory tests indicated original designs were workable. The first field test was made in the Four Corners area. A series of eight runs was made, varying from about 5,300 to 5,500 feet. A 1-foot test interval between packers was used and the drill pipe was repositioned five times for different zones.

The tool functioned properly. However, the pressure recorders and clocks suffered severe damage. A change was made in sampler centralizers and method of mounting pressure recorders to correct this weakness. Laboratory and field tests since have proved that the new centralizers and shock absorber recorder mountings provide ample protection for the pressure recorders.

On the second field test, in the same area, the sampler was run 24 times at various depths between approximately 5,300 and 5,500 feet with 5 and 10-foot test intervals. Pressure recorder and clock failures were reduced to two out of 48 recorder runs (two recorders per run). One clock stopped before it started in the hole, and one time the clock clutch became disengaged going into the hole.

Other weaknesses did develop, however, which had not shown up on previous test. Of the 24 runs, 11 were misruns resulting from improper seating and failure to open the tester valve.

At that time, the seal rubber was attached to the seal seat in the drill pipe. A combination of wear and effects of oil base type mud damaged the seal rubber and resulted in four additional misruns. Nine runs were satisfactory and produced very good pressure charts. Since the operator was interested only in obtaining static pressures, sample volumes were reduced to provide maximum use of test periods for pressure buildup.

Seal changed. To provide a more positive seating arrangement, a solid spider centralizer was used in place of the spring centralizer used before. A guide sub was added to restrict lateral movement of the seat and sampler to aid in proper alignment for seating the sampler. The seal rubber was removed from the seat in the drill pipe and placed inside the sampler. This permits visual inspection and replacement between sampler runs.

Another factor encountered was fluid resistance to running the sampler in drill pipe. With a viscosity of about 125 seconds with a Marsh funnel, the sampler ran very slowly in 4½-inch internal-upset drill pipe with 4½-inch full-hole tool joints. Outside diameter of the sampler was reduced from 2.66 inches to 2.38 inches to relieve this situation. Clearances and pressure-release ports within the sampler valve also were increased to provide better performance in viscous fluids.

FUTURE DEVELOPMENTS

Possible future developments under consideration are: (1) conversion to a hydraulic sampler valve which will permit a dual closed-in pressure test. (2) Addition of a small chamber to trap reservoir fluids at reservoir conditions for laboratory PVT analysis. These developments will depend upon interest shown by the industry.

From a paper entitled "Multiple Zone Tester," by Pat Chisholm, Halliburton Oil Well Cementing Company, presented at Southern District Spring Meeting of API, Production Division, March 16-18, 1960, San Antonio, Texas.

ACKNOWLEDGMENT

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About the Author

Pat Chisholm received his B.S. degree in petroleum engineering from Louisiana State University in 1955. He joined Halliburton Oil Well Cementing Company in February 1957 where he has worked with the design and development of formation testing tools. He is a member of AIME.

AN API FEATURE

STRIPPER LEASE A.C.T. CAN SAVE YOU MONEY

Skid-mounted, low cost units equipped with positive displacement meters are applicable to leases producing 30-200 bopd

By Paul W. Truman, Senior Petroleum Engineer
Sinclair Oil and Gas Company, Tulsa

Low cost lease automatic custody transfer (LACT) equipment installed on stripper leases will save more money in over-all operations than LACT installations on leases of high productivity. Prefabricated skid-mounted LACT units, complete with fail-safe features and using positive displacement meters, have been designed, constructed and installed on small leases with all equipment connected in a proper flow pattern. These relatively low cost units require a minimum of field connection expense and maintenance. Experience has shown application of positive displacement (PD) meters to this type of LACT installation to be an economical and accurate means of quantity determination in crude oil measurement.

Several producing and pipe line companies now are using a master meter or a combination surge and meter-prover tank to establish an acceptable meter factor. Where either of these two methods of proving meters can be agreed upon, then a special meter-prover tank is unnecessary and application of LACT by PD meter to stripper lease production is most economical.

The cost of most early LACT installations was such that it soon became apparent that its use might be limited to only those leases producing 1,000 bopd or more, unless the initial cost of the installation could be reduced. Since most producing companies have a number of leases which produce from 30 to 200 bpd, it was believed that here

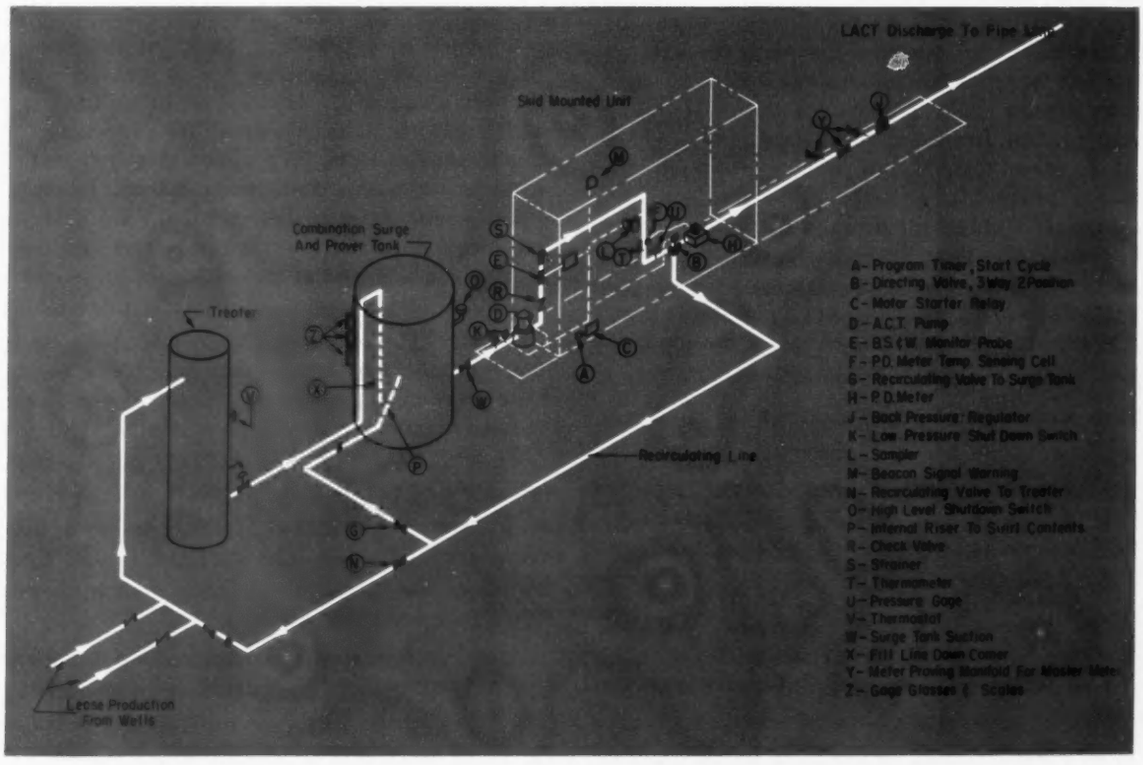

LACT Discharge To Pipe Line
Skid Mounted Unit
Combination Surge And Prover Tank
Treater
Recirculating Line
Lease Production From Wells
A- Program Timer, Start Cycle
B- Directing Valve, 3 Way 2 Position
C- Motor Starter Relay
D- A.C.T. Pump
E- B.S.&W. Monitor Probe
F- P.D. Meter Temp. Sensing Cell
G- Recirculating Valve To Surge Tank
H- P.D. Meter
J- Back Pressure Regulator
K- Low Pressure Shut Down Switch
L- Sampler
M- Beacon Signal Warning
N- Recirculating Valve To Treater
O- High Level Shutdown Switch
P- Internal Riser To Swirl Contents
R- Check Valve
S- Strainer
T- Thermometer
U- Pressure Gage
V- Thermostat
W- Surge Tank Suction
X- Fill Line Down Comer
Y- Meter Proving Manifold For Master Meter
Z- Gage Glasses & Scales

FIGURE 1—Flow diagram for skid-mounted LACT unit installation with positive displacement meter, 30-200 bopd capacity. A modified surge tank or master meter is used for proving.

AN API FEATURE

Stripper Lease ACT

LACT could best serve all parties concerned, provided installation could be justified from an economical standpoint.

Various methods of accomplishing LACT have been advanced and proved practical. This article covers the application to stripper lease operation of LACT by positive-displacement meters. Such installations as described herein are in operation and have proved economical to install, accurate in custody-transfer determinations, practical to operate, and require a minimum of maintenance.

When PD meters with automatic temperature compensation are used on small leases, 30 to 700 bopd, it is desirable to bring the temperature-compensating devices to the approximate temperature of the oil to be delivered before this oil passes through the meter to the pipe line. To accomplish this, the temperature-sensing bulb is removed from the meter case and equipped with a 60-inch capillary tube. The bulb then is mounted upstream from the directing valve, where it senses the temperature of the oil from the surge tank which is being recirculated before transfer is begun through the PD meter.

In the interest of accuracy of measurement by PD meters, it is advisable to make delivery to the pipe line in increments of not less than 30 barrels each. As shown in Figure 1, there are no conventional "start" and "stop" float-operated switches installed in the surge tank. The LACT cycle is initiated by a program timer (A) which may be set to start as many transfer cycles per 24-hour period as may be required to transfer average daily production in increments of not less than 30 barrels each.

Example for one transfer cycle (refer to Figure 1). At 8 a.m. program timer (A) causes directing valve (B) to move to the "circulate" position. Electrical contacts are then actuated by the position of the valve stem to latch up the motor starter (C). This causes the ACT pump (D) to take suction from the surge tank (W). Oil is pumped at 8 psi—1 barrel per minute—through the BS&W monitor probe (E) and the PD meter temperature-sensing cell (F) only (not through the meter or into the sample container), then through the directing valve (B) and finally through the normally open recirculating valve (G) into the surge tank.

Starting a transfer cycle in this manner accomplishes the following:

1. Eliminates conventional "float switches" in the surge tank.
2. Tests the 3-way, 2-position electrically operated directing valve for mechanical or electrical failure before each ACT run is made. Should the valve fail to operate, the ACT pump cannot start.
3. The BS&W monitor probe cell is flushed out and brought to the approximate temperature of the oil to be delivered before oil is allowed to pass through the PD meter.
4. The temperature bulb and its compensator mechanism are brought to the approximate temperature of the oil to be delivered before it passes through the meter.
5. Any gas or air which may have accumulated during downtime will be flushed into the surge tank and not through the PD meter (H).

After a predetermined interval of recirculating (approximately 15 min), the timer causes the directing valve (B) to move to "deliver" position, thereby allowing pump pressure to open the back-pressure regulator valve (J) and permit oil to pass through the PD meter (H), on which the temperature-compensating devices have become adjusted to the temperature of transferred oil. The register on the PD meter now indicates barrels corrected to 60° F. The meter is equipped with a ticket printer.

The ACT pump (D) will continue to take suction from the surge tank and deliver through the BS&W monitor probe (E) (monitor sensing merchantable oil), the sampler (now operating), the PD meter and the back-pressure regulator (J) to the pipe line at a rate of approximately 31.5 gpm at a pressure of 10 psi maximum. Pumping continues until the liquid level in the surge tank is lowered sufficiently to cause the low-pressure shutdown switch (K) (located in the pump suction line) to terminate that transfer cycle. The range of the low-pressure shutdown switch is adjustable to provide sufficient storage in the surge tank to allow the oil to become stabilized.

Sampler and BS&W monitor. The sample valve is located in the center of the vertical stream, upstream of the directing valve. However, because the sample valve is actuated electrically, it can never take a sample until the directing valve is directing oil to the PD meter and pipe line. Electrical contacts located on the directing valve stem itself serve to control this feature.

Oil passes through the monitor probe (E) in a vertical stream at all times while the pump is running. Should the BS&W content exceed some predetermined percentage, the monitor opens the directing valve (B) and oil is recirculated into the surge tank. At the same time any further delivery to the pipe line is prevented until the oil has been cleaned up. The beacon signal (M) is activated, calling attention to this condition. Operating personnel may then open valve (N), close valve (G) and recirculate surge-tank contents through the treater. Lease production will continue to recirculate until the oil is cleaned up or the surge tank reaches the high-level shutdown switch (O), which will shut in all wells.

Controls. The program timer (A) may be set for as many "starts" per day as may be needed to transfer the daily production. There are 96 start points available per 24-hour period.

The "CIRC," "OFF," "AUTO" selector switch, when set to "AUTO" position, allows the timer to start the ACT cycle. When set on "CIRC" position, the directing valve (B) will open and start the pump. Recirculation will continue until the selector switch is returned to "OFF" or "AUTO" position.

After the selector switch has been returned to "OFF" or "AUTO" position, oil will be transferred through the PD meter to the pipe line until the normal low level in the surge tank is reached or until the "STOP" button is pressed. When the selector switch is set to "OFF" position, no starts are possible from the program timer.

Fabrication. The entire LACT unit is shop-fabricated with all equipment, except the ACT pump and pump-start relay. These are contained within a standard galvanized four-door meter house which is insulated and electrically heated to maintain a minimum of 60° F. The meter house, ACT pump, suction manifold, meter-proving manifold, back-pressure valve and discharge manifold are all connected, wired and mounted by the fabricator on a steel skid approximately 9 x 3 x 7 feet. Total weight is under 2,000 pounds, and total cost is under $3,500.

Installation. The complete skid-mounted LACT unit is easily transported to the lease site and requires no concrete foundation or lease gas connection. Only three pipe connections are required in the field installation—one 2-inch line from the directing valve to the surge tank; one 4-inch line from suction to the surge-tank outlet valve; and one 2-inch line from the discharge manifold to the pipe line connection. All conventional and usual "fail-safe" features are built into the skid-mounted unit.

Only four electrical connections are necessary in the field to provide two additional fail-safe features: a thermostat in the heater to shut down the unit should treater temperature become abnormal, and a high-level float switch on the surge tank to shut in the lease. In addition, a rotating beacon light to warn of any abnormal condition at the LACT unit. Of course, a connection must be made from the electric service pole to the skid-mounted unit. Electrical requirements are 3-kw, 115 to 230-volt, single-phase—readily available and making it unnecessary to build in 3-phase power service.

Economics. This simplified installation greatly reduces costs of both labor and material, thereby creating more favorable economics for LACT in stripper lease operation.

In the interest of further economy in LACT for small lease operation, the following methods are suggested for proving temperature-compensated PD meters. The use of either method must be mutually agreeable to all parties concerned.

1. On meter-proving day, the pipe line company would furnish a portable master meter to be connected in series with the LACT unit discharge test manifold at (Y), upstream from the back-pressure regulator. The master meter should be precalibrated and equipped with a register and standard thermometer.

2. A standard welded steel stock tank could be modified for use as a combination surge and prover tank. The interior of the tank should be coated with an epoxy resin compound to reduce internal buildup of paraffin, etc. A strapping table in $\frac{1}{16}$-inch increments would be prepared in accordance with API Std 2501 to determine the volume of the vessel. Only the lower portion of the tank would be used as a surge tank for daily production and automatic custody transfer through PD meters.

The upper two-thirds of the vessel would remain clean and be filled to the upper level on meter-proving dates only. For stripper lease operation, the frequency of meter-proving dates should be determined by the metered barrels throughput, rather than on a monthly or elapsed-time basis.

Contents of the tank would be circulated for one hour or longer on meter-proving day to insure a mean temperature before proving the meter. Immediately after circulation, an acceptable "meter factor" could be established.

Both of the preceding methods are now being used by various pipe line and producing companies, and satisfactory meter factors are being obtained. The use of either method, of course, effects a considerable saving over the cost of providing a separate meter-prover tank for each LACT unit to obtain a satisfactory meter factor.

It is believed that the greatest opportunity for automation in crude production lies in its adaption to small leases. To be of value in small lease operation, the units must be rugged, accurate, capable of long unattended operation with a minimum of maintenance and fit into the over-all economics of production costs. Experience has shown that use of PD meters provides a most economical, accurate and trouble-free means of volumetric determination for this type service.

This article taken from a paper entitled "Application of LACT by Positive-Displacement Meters to Stripper Lease Operation" and presented at the Spring Meeting of the API Mid-Continent District Division of Production, Wichita, Kan., March 30-April 1, 1960. —**The End**

About the Author

Paul W. Truman is a senior petroleum engineer with Sinclair Oil and Gas Company in Tulsa. His duties include electrical engineering, automation design and contsruction work in Sinclair's production department. He is a member of API and has previously published an article on electrical control of LACT units.

ABSTRACTS OF API PAPERS

DALLAS

Application and Evaluation of Air-Hammer Drilling in the Permian Basin

Drilling results indicate that penetration rates may be more than doubled by use of the air hammer. This is based on comparative performance between air-rotary drilling and air-hammer drilling on five wells in the Permian Basin. In some instances, drilling rates with the air hammer are three to four times greater than with air rotary. Reduction in deviation by air-hammer drilling has been excellent within the Permian Basin, while at the same time maintaining high penetration rates. Air-hammer bit footage was extended in specific instances and

over-all averages indicate much greater footage per bit may be expected when compared to rotary air drilling. Optimum performance of the air hammer is obtained with between 200 and 300 psi air pressure, therefore no changes in the normal air compressor services are required other than 10 to 20 percent more volume to maintain a clean hole while drilling at higher penetration rates. More work on design must be done and more evaluation is necessary before the tool generally is accepted by the industry. The tool is designed to operate while mist drilling but no attempts have been made in the Permian Basin toward evaluating its performance under those conditions. All air-hammer drilling in the tests covered by this report was done with the 6¾-inch tool.

(Application and Evaluation of Air-Hammer Drilling in the Permian Basin, H. F. Downs, Technical Drilling Services, Inc., presented at Southwestern District, Spring Meeting of API, Production Division, March 2-4, 1960, Dallas.)

A New Completion Technique—Sand Erosion

The sand-erosion process and its applications in oil or gas wells are practically unlimited. To date, the sand-erosion process has been used successfully to perform a multitude of both ordinary and unusual well operations. Some of these are: (1) Conventional perforating of wells in casing ranging from 2⅞- to 8⅝-inch and to depths of 10,000 feet; (2) fracture-initiation perforating of cased wells to depths of 7,800 feet; (3) perforating of open-hole completions with both the fracture-initiation and conventional patterns; (4) scouring and removal of skin damage from open-hole completions; (5) under-reaming of open hole and cased completions; (6) selective perforating of 2⅞-inch casing strings in single and multiple tubingless completions; (7) perforating and testing of multiple zones; (8) cutting out and removing scale, debris, etc. from well bore; (9) perforating open-hole and cased completions subsequent to cement squeeze operations; and (10) perforating and/or cleaning up water or gas injection wells in order to facilitate injection. The use of the process to stimulate formations also may prove to be important. Based upon the results obtained and the potential of the process, hydraulic perforating is a significant innovation in well completion techniques.

(A New Completion Technique—Sand Erosion, Robert Wade Brown, Jack L. Loper, The Western Company, presented at Southwestern District Spring Meeting of API, Division of Production, March 2-4, 1960, Dallas.)

Evaluation of Wells for Re-Fracturing Treatments

To determine feasibility of re-fracturing a well to obtain more successful results with a more suitable treatment, the production history, formation characteristics, completion method and previous treatments must be correlated. Much consideration has been given in recent years to fracturing but most studies have been aimed at the ideal fracturing operation wherein the formation characteristics are assumed to be homogeneous. Since a large percentage of wells previously treated were fractured without benefit of the best engineering available, trial-and-error operations were developed, some of them being carried from one field to another. Each field, however, has its own recommended treatment. Among the conclusions reached by the current study are: (1) Formation characteristics influence the fracture pattern formed; (2) fracture patterns may be altered by the use of selective methods of fracturing; (3) the practice of overflushing to move propping agents away from the well bore is detrimental to realizing the full productive capacity of fractures; and (4) past fracturing data will indicate if previous use of selective plugging agents has been effective in causing intended multiple fractures to form.

(Evaluation of Wells for Re-Fracturing Treatments, Philip Johnson, Texas Technological College, presented at Southwestern District Spring Meeting of API, Division of Production, March 2-4, 1960, Dallas.)

Production of Dually Completed Wells With Tandem Rod Pumps

Artificially lifting dual zones has proved to be both economical and efficient. Cities Service Oil Company, since 1949 has been experimenting with methods of pumping deep duals and, in 1956, made their first tandem pump installation. In 1957, several shallow dually completed wells were equipped with parallel tubing strings and tandem pumps on a single rod string. All wells were equipped with 5½-inch casing. The favorable experience of these installations indicated similar applications could be made, with similar equipment, in deep duals. Greatest advantage of the tandem rod pump installation is that it is more economical as it allows a reduction in the cost of drilling and completing and installation of artificial lift equipment. If the parallel tubing strings are run in when the well is completed, either or both zones can be converted to artificial lift without killing the well or round-tripping tubing. A disadvantage of the tandem rod pump installation is that production control is a problem. High pressures in one or the other of the zones may create control difficulties. A comparison of monthly direct equipment expense, including all repairs, pulling and paraffin cutting, shows duals to have an equipment expense of 0.02203 cents per barrel of oil, and singles an equipment expense of 0.02969 cents per barrels of oil.

(Production of Dually Completed Wells with Tandem Rod Pumps, M. C. Boyd, Cities Service Oil Company, presented at Southwestern District Spring Meeting of API, Production Division, March 2-4, 1960, Dallas.)

A Background for Creative Thinking

During a period in which the United States' compulsory education system was eradicating illiteracy and sending relatively high percentages of the population to college, the following paradox was taking place:

- There were marked decreases in total and per-capita U.S. patent issues
- A marked failure of U.S. scientists to win Nobel prizes for outstanding discoveries

- U.S. manufacturers were having increased difficulty in meeting foreign competition.

Thus, it appears that the United States is exhausting the backlog of creative ideas provided by its ancestors without knowing the meaning of creative thinking or the critical relationship it bears to civilization.

From an analysis of thinking in general and creative thinking in particular, it is possible to propose several long-term measures to provide a greater quotient of deep and creative thought through greater consideration of the thought process itself, through intellectual broadening, and through support and stimulation of individual minds.

(A Background for Creative Thinking, Mercer H. Parks, Humble Oil and Refining Company, presented at Southwestern District Spring Meeting of API, Production Division, March 2-4, 1960, Dallas.)

New Interest in Public Affairs

The "new interest" in public affairs refers to the growing concern of the business community over its role in matters having to do with politics and government. It also refers to the movement now in the making—and which is evidenced by numerous speeches, articles, books, the appearance of new groups and organizations, and even consultants in the public affairs field.

This new interest is further evidenced by the formulation of company programs aimed at encouraging greater participation by employes in the democratic processes of this country.

Why has Continental Oil Company committed itself to a more active role in public affairs? What does it expect from its public affairs program? It can be answered in terms of a more self-reliant citizenry, sound government, or even in terms of opportunity or freedom for future generations. One other answer is sometimes suggested—to which we very definitely do not subscribe—and that is to create some kind of countervailing anti-union force. We reject that approach.

A proper objective toward which businessmen, including management, may direct their efforts is the maintenance of a favorable economic climate in which business enterprise may continue to earn reasonable profits, without which our economic system and our form of government—and our free American society which depends on them—would in due time be a thing of the past.

(The New Interest in Public Affairs, Harold S. Skinner, Assistant to the President and Director of Public Affairs, Continental Oil Company, presented at the Southwestern District Spring Meeting of the API, Production Division, March 2-4, 1960, Dallas.)

Conservation—Total or Partial?

Elimination of weaknesses in present conservation laws, rules, regulations and practices is the best answer to all critics of the Texas oil industry, in the opinion of the author. Among the changes recommended are: (1) Pooling on the established spacing pattern would be compulsory and would eliminate the over-drilling which now prevails in townsites and where there are segregated small tracts; (2) use of arbitrarily selected allocation formulas would be discontinued and, instead an allocation formula would be adopted for each field that would give to each well and tract its fair share of the oil or gas underlying the tract, but no more; (3) temporary spacing rules would be adopted after completion of the discovery well in a new field and before offsets are connected; (4) any town or city in which, or near which, oil or gas is discovered should immediately adopt an ordinance which would protect the life and property of its citizens from the hazards which accompany the exploration for and production of oil and gas; and (5) conservation laws would be shored up and modernized to meet existing problems before we are faced with federal laws that could and would lead to federal control of the industry.

(Conservation—Total or Partial; Michel T. Halbouty, Consultant and Independent Operator, presented at Southwestern District Spring Meeting of API, Division of Production, March 2-4, 1960, Dallas.)

SAN ANTONIO

Rheological Properties of Gel Cements

To control lost circulation while cementing, various additives such as bentonite, pozzolans, diatomaceous earth and gilsonite are used to obtain lighter weight slurries. Little information was available, however, on the viscous properties of cements so a preliminary investigation was made to determine the rheological properties of API Class A cements containing up to four percent bentonite under simulated bottom-hole temperatures. The plastic viscosity of all slurries tested remained essentially constant regardless of their bentonite content or aging temperature. The average value was 56 cp with an average deviation of plus or minus 10 percent. Depending upon the aging temperature, increasing the percentage of bentonite in a slurry from zero to four percent caused a two- to three-fold increase in yield point. As a consequence, although a bentonite slurry will produce lower hydrostatic gradients than a neat slurry, little, if any, reduction in flowing pressure gradients will be realized when using a bentonite slurry.

(Rheological Properties of Gel Cements, William R. Holden and Ernst J. Leidner, Louisiana State University, presented at Southern District Spring Meeting of API, Division of Production, March 16-18, 1960, San Antonio, Texas.)

Turnkey Slim Hole Drilling in Mississippi

The cost saving benefits of slim hole drilling, combined with the further savings involved in turnkey contracts, are accounting for a rapid increase in slim hole completions in certain parts of Mississippi. Well depths in the areas discussed average 6,700 feet. The turnkey type of slim hole contract, where the contractor provides numerous third-party services, has been particularly beneficial to independent operators who, because of lack of experience

in a new drilling method, otherwise might hesitate to go the slim hole route. The turnkey feature provides economical supervision of routine matters that arise on the job such as road and location preparation, running surface pipe and supervising mud programs. Reduction of costs to the operator is possible when he makes more efficient use of the contractor's equipment and personnel. Comparative costs showing typical savings involved in slim hole completions, are illustrated with tables and curves. Future advances in slim hole drilling performance will depend primarily on: (1) improvements in existing bits or development of new types of cutting tools; (2) adapting all logs and testing devices to small hole operations; and (3) wider acceptance of small casing completions.

(Turnkey Slim-Hole Drilling, Mississippi, J. W. Arnold, Woolf & Magee, Inc., Tyler, Texas, presented at Southern District Spring Meeting of API, Production Division, March 16-18 1960, San Antonio, Texas.)

Turnkey Drilling in South Texas

The cost consciousness of the oil and gas industry in recent years has prompted operators to turn to a type of turnkey contract for the drilling of certain of their wells. Where this has meant a shifting of responsibilities from the operator to the contractor, South Texas drilling contractors have required a price commensurate with the risks involved. A limited survey of these contractors indicates they feel this system is an uneconomic one for operators. Operators, in seeking some type of turnkey drilling contract, probably have these basic reasons: (1) To avoid necessity of maintaining a large staff; (2) to transfer supervision; and (3) to transfer responsibility. Operators using South Texas contractors will be able to have wells drilled on a turnkey basis involving transfer of responsibility with certain cost stops inserted and by paying a premium for being insured.

(Turnkey Drilling in South Texas, Walter Kalteyer, Hunt Drilling Company, presented at Southern District Spring Meeting of API, Division of Production, March 16-18, 1960, San Antonio, Texas.)

Drilling-Mud Programs in the Texas Gulf Coast Area

A review is made of drilling mud practices in the Texas Gulf Coast to provide not only a general survey of current mud programs, but to point out the principal changes that have occurred in recent years. Progress has been made toward solving such problems as sloughing shale, high pressure, high temperature and soluble salts. The following factors are discussed in detail: Aggregated mud systems; lime-treated muds; gypsum-treated muds; mud weight; flow properties; filtration; lubrication; loss of circulation; completion fluids; and detailed examples are given of the planning involved in typical mud programs. Among the changes noted in drilling mud practices are: (1) lime-treated muds have been replaced by gypsum-treated muds as the type favored for deep wells; and (2) surfactants are being used widely and for various applications in addition to those for which the products first were proposed.

(Drilling-Mud Programs in the Texas Gulf Coast Area, K. D. Tanner, George R. Gray, Baroid Div., National Lead Company, presented at the Southern District Spring Meeting of API, Division of Production, March 16-18, 1960, San Antonio, Texas.)

Application of Hydrocarbon Recovery Units

Experience gained at a number of installations in fields in Louisiana, with units of various types, and ranging in capacity from 5 to 24 MMcf per day, has indicated that hydrocarbon adsorption recovery units provide a dependable method for dehydration and recovery of hydrocarbon from high pressure gas streams. Application, in general, should be limited to small, lean-gas streams. The process is simple and, by using conventional controls, operation can be automatic and unattended. Attractive payouts can be realized with these units if properly applied and operated, this being particularly true on those streams where dehydration also is required. There has been a growing acceptance of short-cycle, solid desiccant hydrocarbon recovery units as a part of gas handling facilities for gas-condensate well production. A great potential exists for these units since they not only dehydrate the gas stream, but also recover hydrocarbons without the need for either a large pressure drop or a separate operating staff. Installed cost of the units, used in the Louisiana fields and referred to in the text, ranged from about $30,000 to $140,000.

(Application of Hydrocarbon Recovery Units, R. C. Visser and H. W. DeYarmett, Shell Oil Company, presented at Southern District Spring Meeting of API, Division of Production, March 16-18, 1960, San Antonio, Texas.)

Creative Thinking in Daily Practice

Increasing man-hour productivity in the United States has been more than nullified by the increase in assets required to support this man-hour performance despite very large increases in engineering manpower and research funds. Anthropological evidence indicates that complex and sophisticated civilizations tend to deteriorate in capacity for creative thought prior to disintegration. However, there are measures which can aid in getting better current solutions to problems of thinking. Experimental work supports the conclusion that direct, intentional and well-designed stimulation of thinking can produce notable results. Efficiency in manufacturing productivity per man-hour, has nearly tripled in the last 37 years. Paradoxically, the country's assets had lost a third of their earning power while productivity and national spending were rapidly increasing. Using the history of eight large oil companies, it was found that in 1947 it required six dollars of assets to produce a dollar of income; and, after inflation took its toll, it required, in 1956, *eleven* 1947 dollars to produce *one* 1947 dollar of income, or nearly double the 1947 requirements.

Considering the combined productivity of men and dollars, the country has suffered a 40 percent decrease in 40 years, during which time expenditures for engineering and research increased forty-fold. Civilization and industrialization have created atmospheres repressive of spontaneous individual thought. To correct this, industry management must seek the good in new ideas rather than seeking to destroy them because of questionable or nonconforming features.

(Creative Thinking in Daily Practice, Mercer H. Parks, Humble Oil & Refining Company, presented at Southern District Spring Meeting of API, Division of Production, March 16-18, 1960, San Antonio, Texas.)

WICHITA

Chemical and Mechanical Means of Maintaining Low-Solids Drilling Fluids

Field experience has shown that, with other factors equal, the lower the content of dispersed clay solids in a drilling fluid the faster is the drilling rate. The lower limit of the percentage of solids often is fixed by the viscosity required to control such problems as sloughing of shale and the efficient removal of cuttings from the hole. Laboratory and field test results indicate that a low-solids mud prepared with bentonite, a powdered free-flowing polymer and soda ash exhibits most of the desirable properties of a conventional mud but favors faster drilling.

The yield of bentonite, expressed in barrels of 15-cp mud per ton of clay, may be doubled by addition of the polymer in a concentration of 0.05 pounds per barrel and soda ash in a concentration of one pound per barrel. The solids content of drilling fluids may be maintained low by treatment with a hydraulic cyclone. A 14-inch diameter cyclone with a 1½-inch diameter underflow, a 5-inch diameter vortex finder and a capacity of 15 barrels per minute removed from drilling mud 99 percent of all cuttings coarser than 230 mesh (62 microns). A unique feature of the 14-inch cyclone tested is that mud is not rejected from the underflow if the feed mud is free of cuttings.

(Chemical and Mechanical Means of Maintaining Low-Solids Drilling Fluids, Arthur Park, P. P. Scott, Jr., and J. L. Lummus, Pan American Petroleum Corporation, presented at Mid-Continent Spring Meeting of API, Division of Production, March 30, 31, April 1, 1960, Wichita, Kan.)

Laboratory Studies of the Effect of Rotary Speed on Rock-Bit Performance

Laboratory data showing the relationships between rock-bit bearing life and rotary speed, drilling rate and rotary speed, and rock-bit tooth wear and rotary speed, show that these relationships combine in a manner resulting in decreased rock bit footage and increased costs at high rotary speeds. Conclusions of the tests indicate: (1) Total bearing revolutions are independent of rotary speed in the range 160 to 1,060 rpm; (2) penetration per bit revolution decreases with increased rotary speed where mud pressure exists at the bottom of the hole; (3) where bearings always limit bit life, footage per bit is reduced at high rotary speeds because of decreased penetration per revolution; (4) while tooth wear always limits bit life, footage per bit is reduced at high rotary speeds because of decreased penetration per revolution and increased tooth wear; (5) optimum constant rotary speed for constant bit weight decreases if bit weight is increased; (6) for a given bit weight, lower costs can be obtained by varying rotary speed according to a specific program than by using the best constant rotary speed; and (7) proper weight in combination with moderate revolutions per minute and good bottom-hole cleaning appears to offer more toward reducing drilling costs than high rotary speeds.

(Laboratory Studies of the Effect of Rotary Speed on Rock-Bit Performance, R. A. Cunningham, Hughes Tool Company, presented at Mid-Continent District Spring Meeting of API, Division of Production, March, 30, 31-April 1, 1960, Wichita, Kan.)

Progress in the Use of Plastics in Petroleum Production

Laboratory and field tests, conducted over the past two years, were made on the three major types of plastic piping materials: (1) extruded plastics; (2) glass-reinforced plastics (GRP); and (3) plastic coatings. It was found that polyvinyl chloride deteriorated when exposed to high concentrations of the diluents in some corrosion inhibitors and injection of these inhibitors into water lines provides concentrating conditions. A new material, rigid polyethylene, recently introduced to oil production, can be used successfully within the property limits set by the supplier and its use in such applications is economically attractive. Heat welding of this new material can be done by roustabouts, using simple, inexpensive equipment. Glass-reinforced plastic line pipe from two manufacturers and tubing from another have been developed sufficiently to give satisfactory service when used within the specified limits. This GRP piping, however, is more expensive than a number of other available corrosion control methods. For internal pipe coatings, the following applications are considered most attractive: (1) Line pipe, where a few isolated leaks can be tolerated; (2) tubing, where chemical treatment cannot be used or at best inconsistently administered; and (3) tubing, in wells, where the expense of tubing failure justifies the use of both coating and chemical treatment.

(Progress in the Use of Plastics in Petroleum Production, R. L. McGlasson and W. D. Greathouse, Continental Oil Company, presented at Mid-Continent District Spring Meeting of API, Division of Production, March 30-April 1, 1960, Wichita, Kan.)

Slim-Hole Completions—Planned Selection of Pumping Equipment

The concept of solid sucker rod pumping changes to a certain degree when sucker tubes are used and fluid is produced through these sucker tubes. Unbalanced hy-

draulic forces exist in sucker-tube installations. The loads on upstroke and downstroke are affected by hydraulic up-thrust and fluid friction tends to increase internal pressure where the fluid is pumped through the sucker tubes, increasing the unbalanced force. A portion of the sucker tube weight is required to overcome this force in certain installations on the down-stroke, resulting in flexure of the threaded joint. Special sucker tubes have been designed to assist in overcoming joint failures. A special application pump and hold-down assembly also assists in overcoming this unbalanced load.

Dynamometer cards show that by loading the annulus with fluid, the unbalanced forces generally are equalized. This increases the minimum polished rod load; also the peak polished rod load. It allows the equipment to operate faster and results in greater net plunger travel; also reduces the joint failures caused by flexure. A special crossover-type pump allows fluid to be produced in the annulus and the gas vented through the sucker tubes. Gas is vented and casing wall is lubricated for better wear of the sucker tube couplings. More concrete and factual information will become available as more installations are made and dynamometer surveys are studied.

(Slim-Hole Completions—Planned Selection of pumping Equipment, R. M. Erskine, Continental-Emsco Company, presented at Mid-Continent District Spring Meeting of API, Division of Production, March 30-April 1, 1960, Wichita, Kan.)

The Appraisal Process of a Management-Development Program

It is essential to the present and future health of any company that a plan be made to meet the recurring problem of effectively manning the ranks of management. It is vital, also, that full opportunity be provided for management members to develop their potential abilities so they may grow in their assignments and be of increased value to the company. One of the answers to this problem is a formal management personnel inventory and development plan which, briefly, would find answers to these questions: (1) What do we have? It would be answered in terms of experience, ability, potentiality and availability. (2) What do we need? This answer would be in terms of the present and the future. (3) What must we do about it? The answer would be in terms of placement, experience and development. The appraisal process and the manner in which it is carried out is the key to an effective management personnel inventory and development plan. The top executive needs just as intelligent and specific a balance sheet as to what his people are, what they are doing and what they *can* do, as he does of the products, materials and money he manages.

(The Appraisal Process of a Management-development Program, Russell L. Switzer, The Atlantic Refining Company, presented at Mid-Continent District Spring Meeting of API, Division of Production, March 30-April 1, 1960, Wichita, Kan.)

CASPER

Penetration Rates Doubled by "Applying" Known Drilling Techniques in Williston Basin

The oil industry is constantly being confronted with the problem of reducing drilling costs. Jet bits, low mud solids and viscosity, and improved rig hydraulics have been applied to the drilling practices in the North Tioga field, Burke County, North Dakota, and has resulted in a 43 percent reduction in drilling time. This amounted to a saving of approximately 8½-days drilling time out of 19.8 days required for previous wells.

The information for comparison purposes was gathered from five wells whereby three of these wells used these above known improved drilling practices. Although data from only five wells are presented in this comparison, a thorough examination of wells drilled by other operators in the field indicates that these five wells are representative of the drilling performance in this area of operation.

(Penetration Rates Doubled by "Applying" Known Drilling Techniques in Williston Basin, K. P. Swenson and H. G. Schmidt, Humble Oil & Refining Company, Carter Division, presented at Rocky Mountain District Spring Meeting of API, Division of Production, April 20-22, 1960, Casper, Wyo.)

High-Volume Pumping

High volume pumping, although not new to the oil producing industry, is becoming more popular because it is one method of decreasing the normal life of many reservoirs and making them more profitable. It is increasing ultimate recovery from reservoirs having low recovery factors under normal or conventional producing conditions. A typical and popular type of high volume pump is the submersible electrical centrifugal unit which has the advantage of being able to lift larger volumes of fluid from greater depths in conventional size casing. Another advantage is that it can be rented for testing purposes, a factor that can save the operator a sizable investment should he find the well will not support a unit of that type. Ohio Oil Company's policy has been to rent equipment of this type for an initial period of 30 days and, if it proves to be applicable to the lifting problem involved, the pump is purchased outright with the rental charge credited to the purchase price. Field performance and typical operating costs of certain high volume pump installations are presented which show the economic advantages of this type of unit. The high volume pump is a means of increasing ultimate recovery and justly can be considered a form of secondary recovery.

(High Volume Pumping, R. W. Parker, The Ohio Oil Company, presented at Rocky Mountain District Spring Meeting of API, Division of Production, April 20-22, 1960, Casper, Wyo.)

And Now—Complete Automation in Waterflooding

Major gaps have been closed, during the past year, in the automatic operation of one of the world's largest water floods, the North Burbank (Oklahoma) Unit. To old devices and equipment has been added a combination of new mechanical and electrical contrivances that permit operations to continue essentially unattended except for preventive maintenance, equipment failures and major changes in conditions. The Unit now produces more than 23,000 barrels daily of oil and 165,000 barrels of water. Some 250,000 barrels of water are injected daily. Automation has been applied to tank batteries, oil treating, lease automatic custody transfer, gas venting and sales, water clarification, relief and oil skimming, water injection and related auxiliary equipment. Among improvements being planned in 1960 are improvement in stuffing-box equipment on producing wells; application of manometer-type controls to tank battery relief tank operations and trouble alarm signals; improved tank cleaning devices and procedures; application of transistorized circuits to LACT instrumentation; and expansion of the use of improved chemical proportioning devices for crude oil treating.

(And Now—Complete Automation in Waterflooding; E. E. Clark, Phillips Petroleum Company, presented at Rocky Mountain District Spring Meeting of API, Division of Production, April 20-22, 1960, Casper, Wyo.)

OTHER PAPERS

Spring Meeting, Southwestern District, Division of Production, Dallas, March 2-4, 1960

Surface-Equipment Corrosion in West Texas, by Jack B. Collins. Paper No. 906-5-A.

Some Biological Aspects of Oil Production, by Paul A. Little. Paper No. 906-5-B.

Dynamic Loads in Sucker Rods, by Joseph R. Norton. Paper No. 906-5-C.

A Review of Oil-Field Automation, by R. W. Jasper. Paper No. 906-5-E.

The Implosion Method of Improving Well Injectivity, by D. D. Setser and J. P. Moran. Paper No. 906-5-H.

High-Density Polyethylene Pipe in the Petroleum Industry, by Leo B. Croley. Paper No. 906-5-P.

Casing Corrosion Experience in the Permian Basin, by Floyd Thorn. Paper No. 906-5-J.

Some Unusual Problems of Deep-Sea Drilling, by W. Bascom, J. McLelland, E. E. Horton and F. Lampiett. Not preprinted.

Spring Meeting, Southern District, Division of Production, San Antonio, Texas, March 16-18, 1960

Proper Preparation for Drill Stem-Testing, by G. E. Wilson and J. R. Holmes. Paper No. 926-5-D.

Development and Exploitation of Water Resources, by Louis Koenig. Paper No. 926-5-H.

Purchase of Gas Supplies in Place, by J. F. Lynch. Not preprinted.

A Chemical Method of Inhibiting the Deposition of Paraffin, by C. F. Parks. Paper No. 926-5-I.

Spring Meeting, Mid-Continent District, Division of Production, Wichita, Kan., March 30-April 1, 1960

Tubingless Well Completions, by Truman T. Branscum. Paper No. 851-34-E.

Case History—Peace Creek Viola Waterflood Unit Reno County, Kansas, by H. J. Lucchi. Paper No. 851-34-F.

A Case History of the Chitwood Simpson Sand Waterflood, by Dan A. Langford. Paper No. 851-34-G.

Potentialities of the Lansing-Kansas City Formation, Hall-Gurney Field, Russell County, Kansas, by C. H. Riggs, R. V. Huff and D. C. Ward. Paper No. 851-34-J.

A Study of Reservoir Characteristics in Three Problem Waterfloods, by Don R. Holbert and George A. Zeito. Paper No. 851-34-K.

Well Stimulation by Hydraulic Fracturing, by F. J. Shell and O. K. Bodine. Paper No. 851-34-M.

Portable Filtration Instrument Featuring Rock Filter, by J. P. Gallus. Paper No. 851-34-N.

Spring Meeting Rocky Mountain District, Division of Production, Casper, Wyoming, April 20-22, 1960

The Turnkey Drilling Contract, by Robert O. Frederick. Paper No. 875-141-I.

The Importance of Corrosion in Waterflood Operations, by H. E. Greenwell. Paper No. 875-14-B.

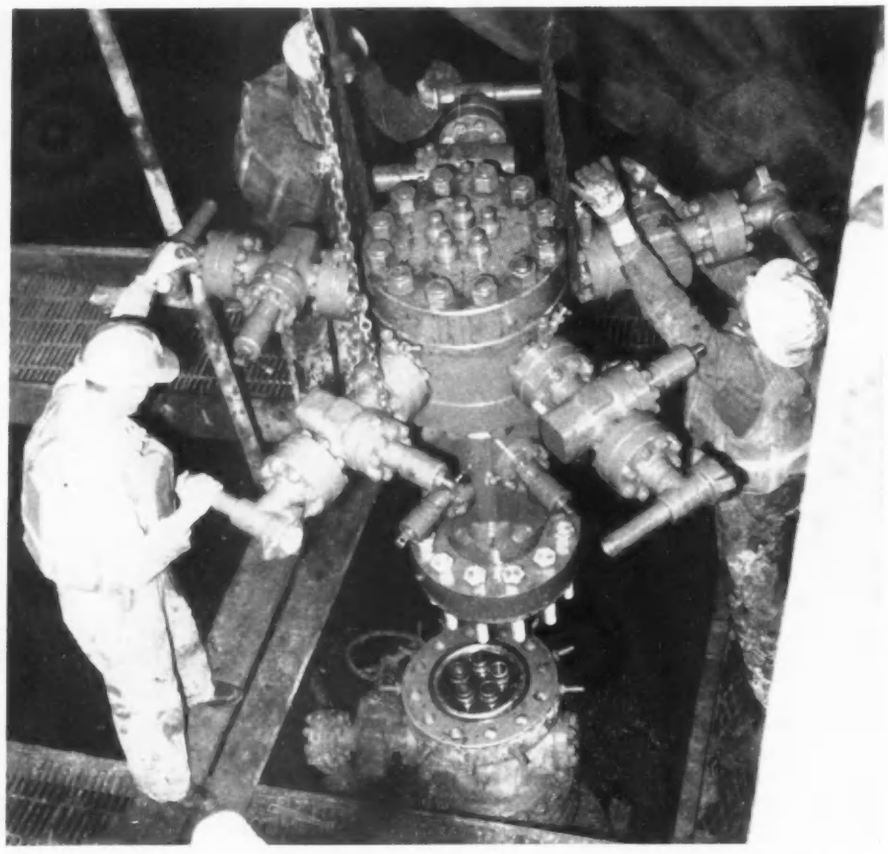
Development and Operation of the Cottonwood Creek Field, by Norman L. Ness, Joseph F. Mueller and Charles J. Boyce. Paper No. 851-14-D.

A Test Installation of Coiled Aluminum Pipe with a Cable-Laying Plow, by M. E. Carlisle. Paper No. 875-14-H.

Water Shut-Off Techniques, by Charles Sufall. Not preprinted.

Oil Well Abrading with Sand Laden Fluids, by E. W. Moore. Paper No. 875-14-K.

Mechanical Reamer for Preparing a Well Bore for Hydraulic Fracturing, by J. L. Huitt, J. L. Pekarek, V. N. Swift and H. L. Strider. Paper No. 875-14-J.



Five strings of 2⅜-inch OD tubing run inside 9⅝-inch OD casing made the quintuple completion possible. Note the five individual tubing hangers.

Sinclair completes world's first quintuple string well

Five strings of 2⅜-inch OD tubing and six hydraulic packers used in unique offshore completion

Sinclair Oil and Gas Company has completed the world's first quintuple string well in the Gulf of Mexico. OC SO439, Well 6, Block 190 Field, Eugene Island Area, Offshore Louisiana, is the first well in the petroleum industry to produce five zones simultaneously from one well bore through five strings of production tubing.

The venture was a joint operation with four companies owning 25 percent each. Participating companies are El Paso Natural Gas Company, People Production Company, Sinclair Oil and Gas Company and Sohio Petroleum Company with Sinclair as the operator.

The quintuple completion is located 40 miles offshore in 72 feet of water. The well was drilled vertically and a 9⅝-inch OD 47 pound oil string was set and cemented.

Six hydraulic packers were used to isolate the producing intervals. Two single string packers were run on bottom and the two lower zones were completed as alternate zone completions. That is, when the lowermost zone is depleted, a plug will be run in the No. 1 tubing string to blank off the lower zone. A sliding sleeve opposite the second zone will be opened and this zone will be produced through the No. 1 tubing string.

A complete technical-operating article covering all phases of the industry's first quintuple completion will appear in the June issue of WORLD OIL.

Other downhole equipment used in the completion consisted of a landing nipple, flow coupling, blast joint, sliding sleeve and safety joint installed between each packer. Also, an adjustable union was used to connect tubing between packers where required. Distance between the quintuple packer and the lowermost single packer was approximately 2,600 feet.

Power operated multiple slips were used to support the five tubing strings while running in the hole. A stripper type blowout preventer which is equipped with a five port stripper rubber was used for well control.

Approximately 30,500 feet of 2⅜-inch OD tubing was run in the hole in 42 hours. The five strings consisted of 2⅜-inch OD plastic coated integral joint tubing. All pipe was hydrostatically tested to 6,000 psi while going in the hole.

The quintuple tubing hanger consisted of a mother hanger with five openings for the individual tubing hangers. The mother hanger was placed on the five tubing strings with the slot opening on the side of the hanger facing in the proper direction for landing in the tubing head. The tubing strings had been properly positioned by orienting the No. 1 tubing string when pipe was first run. The individual tubing hangers were made up on the tubing strings and then landed in the mother hanger.

A single block Christmas tree composed of five master valves then was installed. Another identical block was landed and flanged on the first block of valves; thus, each zone was equipped with double master valves. Wing valves were used to complete the tree.

The 11.7-ppg mud was displaced with 11.2-ppg $CaCl_2$ solution by reverse circulation out the No. 5 tubing string. After the casing and No. 5 string had been completely displaced, the quintuple packer was set by dropping a ball down the No. 5 string. The remaining strings then were displaced and packers were set.

The well then was swabbed in and placed on test. —**The End**

PART 1

How to establish well-density control

- **What are the pitfalls to watch in preparing pooling declarations?**
- **How can they be avoided?**

You will find the answers in this highly informative report on the three most common lease consolidation methods

Editor's Note: Today there are approximately 800 projects to increase ultimate recovery by pooling common sources of oil and gas supply in the United States, compared with 60 reported by the Interstate Compact Commission in 1948. This fast-growing trend to well density control is another indication of the oil and gas industry's interest in more economical and efficient operations.

As a service to those seeking information on well-density control, WORLD OIL is presenting this two-part series describing the three most common contractural methods.

Pooling declarations are described in detail in the following article. Next month the two remaining methods will be described.

By John H. Folks, Central Division Landman
Humble Oil & Refining Company
Carter Division, Oklahoma City

THE MOST COMMON contractural methods of accomplishing well-density control are:

- Pooling declaration
- Voluntary unitization agreements
- The community lease

POOLING DECLARATIONS

Of the three methods to be discussed, the declaration of pooling is the most practical and economical. Since it has the effect of vesting ownership, it should be employed only after thorough consideration, and only by those skilled in its usage.

A pooling declaration is a written statement normally prepared by the operator, which outlines the purposes, desires and intention of the parties, together with specific references to the leases described and the unit area to be established by pooling.

The right to rely on such a declaration must be found

Why the Trend to Well-Density Control?

UNIT OPERATIONS are adding hundreds of millions of barrels to the liquid hydrocarbon reserves of the United States, and are adding substantially to the incomes of all interested owners.

While the success of leasehold consolidation is usually gaged in terms of increased numbers of barrels of oil or condensate to be produced, the substantial increase in recovery of natural gasoline, liquefied natural gases, and the saving of natural gas for sale to pipe lines represents a substantial accomplishment in conservation. In a number of instances, sulfur recovery operations result from unit agreements.

Unit operation is particularly well suited to marginal oil fields, particularly when operators are at the time of initial development willing to recognize the marginal status of a reservoir. In too many instances the effort to substitute close well spacing for unit management and pressure maintenance has caused the waste of many millions of barrels of oil and gas in the less prolific fields of the United States.

It is in matters such as this that unit operations serve as a practical way to substitute conservation for destructive competition.

The time to plan for unit operation is early in the development of a field so that wide well spacing may occur with the remaining wells to be drilled, located at the most effective sites on the structure.

in the lease. In other words, the lessee must have paid for this right at the time all other rights specifically set out in his lease were purchased.

Pooling clause. There are several reasons why pooling clauses work to the advantage of the parties concerned, including:

1. If leased premises are offset so that drainage is taking place, the lessee may find unitization completely inadequate.

2. As a result of the division of royalty interests, it is not unusual for a year or more to pass during which active efforts are made to secure all of the signatures to a voluntary unitization agreement.

3. Also, the drilling of an individual unit may be delayed pending outcome of countless contested hearings before administrative bodies relating to establishment of drilling units for an entire reservoir.

Briefly stated, the oil and gas leasing clause grants the lessee power to consolidate the lessor's mineral interest with other mineral interests to form a drilling and producing unit—and give him definite and flexible right to pool at the time the lease is taken.

Thus, to the operator interested in proceeding with orderly development, the pooling clause is an invaluable aid.

Use and effect of the pooling clause. The courts have quite generally held that the lessee must exercise good faith in the formation of units when relying upon pooling clauses to do so.

It is presumed that including acreage into a unit which lies across a fault or clearly off structure prior to wildcat drilling would constitute an act in which good faith would be subject to question. Or, if, after establishing production, lessee should attempt to include acreage which had been proven nonproductive, surely such an act would be the subject of serious question.

Many pooling provisions authorize consolidation of leaseholds with other leaseholds. A strict interpretation would not permit unitization of less than all the lands covered by all the leases affected.

The courts have generally held that since the leases contain provisions for partial assignment, such a strict interpretation was not the intent of the parties, and have permitted units to be formed of the size existing in the field. Whether a unit slightly in excess of that authorized (caused normally by irregular large sections along correction lines) would be construed as valid is not known.

Contiguity of pooled tracts. In the absence of a specific provision, if one would ask if all of the tracts which comprise a pooled unit should be contiguous to one another, the quick answer "yes" would be returned. This illustrates the danger inherent in general statements made in exercising pooling rights.

The rule of reasonableness seems to be the only sure rule.

As an illustration, pooling of noncontiguous tracts could be very reasonable in certain circumstances and be to the best interest of the lessor. In the development of certain gas fields in the state of Kansas, field rules have been established by the Corporation Commission providing for an allowable based upon 640 acres.

The average lease probably covers a 160-acre tract, or less. Orderly gas development demands that drilling units of 640 acres be established. In fact, in most instances one gas well to 160 acres receiving a one-fourth allowable would be uneconomical.

As the fields are developed, tracts become isolated because of the diversified ownership of the leasehold interest. Toward the end of the field's development it might be necessary to place together four separate noncontiguous isolated tracts of 160 acres into one pooled unit with each of the noncontiguous owners drawing his fair share of the gas from a single well placed upon one of the tracts.

The necessity for the formation of such units has been recognized by the Kansas Corporation Commission, and, in such instances of hardship, exceptions granted to the field rules are not uncommon.

Necessity for complete pooling. A great responsibility rests upon the operator preparing the pooling declaration to insure that every royalty interest within the proposed unit is effectively unitized. The inclusion of a tract which does not authorize pooling, or which is not otherwise consolidated into the proposed unit, causes the pooling to fail.

In a Louisiana case pooling was attempted when one of the leases within the proposed unit did not authorize pooling. The court in referring to the lease pooling clause said, "Obviously, the only meaning that this provision of the lease could have was that the lessor granted to the lessee authority to combine his lease with any other land or lease in the vicinity which the oil company also had authority to unitize."

Holding of outside acreage. When only a portion of the leasehold is included within a pooled unit the question immediately arises as to the effect of such pooling on that portion of the leasehold lying outside the pooled unit.

Will production within the pooled unit, but not upon a portion of the lease in question, hold that portion of the lease outside of the pooled unit? In the absence of a provision in the lease to the contrary, the courts have uniformly held that production anywhere within the pooled unit will hold not only that part of the lease falling with the boundary of the pooled unit, but also will hold that portion of the lease which lies outside of the pooled unit.

The language of the pooling clause should be studied in each instance to insure compliance with the intention of the parties as expressed therein. By the inclusion of language within the pooling clause, the parties can agree that the acreage lying outside of the pooled unit shall not be held by production within the unit and that delay rentals shall be required to be paid on such acreage outside the unit.

In the absence of express language in the lease to the contrary it may be generally stated that either the commencement of a well or production within a pooled unit will hold and extend the terms of all portions of leases which contribute lands to the pooled unit.

Exercising the right to pool. Whether preparing a declaration of pooling or examining a declaration pre-

pared by someone else, there are two precautions that should be taken.

First, an examination of the particular pooling clauses found in each lease must be made to determine if it contains the right to form the particular type of pooled unit desired.

Second, an examination must be made to determine the source of the power conferred upon the lessor which authorizes him to grant pooling rights in the oil and gas lease.

Examination of clauses. As an example of the need for careful examination, one pooling clause in wide use states that the size of the unit cannot exceed the minimum-size tract on which a well may be drilled under the laws, rules or regulations in force at the time of such pooling or unitization.

"Lessee is hereby given the right at its option, at any time and from time to time, to pool or unitize all or any part or parts of the above described land with other land, lease, or leases in the immediate vicinity thereof, such pooling to be into units not exceeding the minimum-size tract on which a well may be drilled under laws, rules, or regulations in force at the time of such pooling or unitization . . ."

This provision often renders the pooling clause useless. As an illustration, in Oklahoma this provision, in the absence of spacing, limits the pooling to a 10-acre unit in the event of production encountered below 2,500 feet and to a two and one-half acre unit in the event of production above 2,500 feet.

Since, under the applicable rule in Oklahoma, the Corporation Commission may grant an exception and allow even greater density, the reliance on such a pooling clause for even 10-acre spacing would be unwise.

In Arkansas, in the absence of spacing, a wildcat unit could not exceed 10 acres. In Kansas, where wells may be drilled as closely as the operator may desire, the clause has absolutely no effect.

Power of lessor. Where did the lessor get his right to grant the pooling clause? If he has the fee simple title, no question arises. If he has a lease covering a life interest joined in by the remaindermen, no question arises.

But what power does an executor, administrator or guardian have to grant a lease containing a pooling clause covering the interest of the estate in the absence of statutory authority? The problem is the same whether it concerns an estate subject to administration by an administrator or executor, or whether it concerns an estate under a guardian of a minor or incompetent person.

The State of Texas, by statutory enactment, has authorized the inclusion of the pooling clause in an oil and gas lease executed by personal representatives of the estates of descendants, minors and incompetents. Prior to statutory enactment the Texas court had reached the conclusion that the pooling clause granted in such a lease was invalid.

Although no other courts appear to have spoken on the matter, the serious question involved has been recognized. One may also question whether a general unitization statute authorizing the probate court to approve a

What to Include in a Pooling Clause

CERTAIN BASIC elements are necessary in a pooling clause so that rights may be safely executed. A good clause should set forth in specific terms:

1. The right to pool all or a part of the acreage covered by the lease. This provision avoids a question as to the lessee's right to include a portion of the leasehold premises within a pooling unit, thereby leaving a portion outside.

2. The right to pool any one or more zones or formations.

3. The right to pool at any time. The inclusion of this provision removes any question that might arise as a result of the exercise of the right to pool after a well has been completed.

4. Authority to establish size of the unit. Recommended limitations are 40 acres in the event of oil and 640 in the event of gas and/or gas condensate, with a tolerance sufficient to cover acreage variations due to irregular governmental sections (usually 10 percent)

5. A statement in the clause that a well anywhere on the unit area shall be considered, for all purposes, the same as if such well were located on any portion of the lands covered by the lease. This insures that drilling operations and ensuing production will perpetuate not only that portion of leases in the unit, but all contributing leases which fall outside.

6. The manner of exercising the right to pool.

7. The method of terminating the pooled unit. All of the pooling clauses must contain a similar right of termination, or consent must be obtained from those parties whose interest is not covered by a clause permitting termination.

Any effort to draft a clause which sets forth the main elements in detail will result in a lengthy clause.

The draftsman has the choice of a lengthy clause which will delineate the rights of the parties and avoid litigation or a short clause which has the effect of inviting litigation. This choice is often made difficult by the fact that the modern oil and gas lease form appears to be growing beyond the limits of the desired single page.

particular unitization will also have the effect of authorizing the court to approve a pooling clause.

Nonparticipating royalty. It is generally accepted that, while the holder of the leasing rights may execute a valid oil and gas lease covering land in which a nonparticipating-royalty interest is owned, he may not join such royalty interest with another interest in a community lease.

In other words, he has no right to apportion the nonparticipant's royalty interest among others by an agreement. The writers expressing an opinion on this subject seem to unanimously agree that pooling provisions incorporated in a lease covering a nonparticipating-royalty interest would be invalid. However, the joinder in the lease by the holder of the nonparticipating interest would render the pooling clause effective.

Term royalty. Attention should be given to the possible effect of a pooling clause covering term-royalty interest. It is usual for the lessee to secure execution of the lease not only by the holder of the term-royalty interest, but also by the owner of the reversionary interest.

The question arises as to the effect of the joinder of the owner of reversionary interest in a lease which contains a pooling clause. The holder of term-royalty interest is usually granted a royalty for a fixed period, and as long thereafter as lands covered by the interest are productive.

If such lands are included in a pooled unit and production is had from such lands, term interest would naturally continue for the life of the production. If production within the unit is from lands other than that covered by term-royalty interest, it has been held that term interest is perpetuated because the owner of reversionary interest signed or ratified a lease which contained a pooling clause.

The more pertinent question is whether the owner of term-mineral interest can execute a lease containing a pooling clause without consent of the reversionary interest, and thus perpetuate his term as a result of production from other lands within a unit so formed. A Texas decision seems to hold that he can, the court stating that if there are no restrictions in conveyances creating term interest, the owner of such term interest has a right to enter into pooling agreements for the unitization of his interest and that production from such pooled units, regardless of where produced within the unit, will perpetuate the term.

Overrides and oil payments. Of interest is the effect of the pooling clause on an overriding-royalty interest or oil payment.

If the lease contained a pooling clause when it was executed, then subsequent overriding royalty or oil payments on the lease would be subjected to the apportionment of royalty occasioned by formation of a pooled unit. Thus, it might be concluded that an overriding royalty or oil payment would not be subject to reduction by apportionment if the pooling clause were added by an amendment to the lease which was later in time than the creation of the override or oil payment.

However, to be considered before reaching this conclusion would be a Texas case holding that in the event of unitization, the owner of an overriding-royalty interest is entitled to payment based upon the royalty attributable to the lands burdened by the override from a well on other lands within the unit.

Termination of the unit. If the Louisiana court is correct in the conclusion that a unitization by use of the pooling clause can only be effected when all of the lands within the proposed pooled unit have been unitized, then it should logically follow that the expiration of a lease within the pooled unit would automatically terminate the unit.

Often, after units have been pooled, drilling is not commenced as soon as is anticipated. In the interim, if a lease expires, the unit automatically terminates. If a new lease is obtained covering the expired interest, or if an extension of a lease covering an expired interest is obtained, then pooling should be re-effected by an entirely new declaration.

When a termination results in the foregoing manner, the lessee may also file a new declaration which would alter the size or shape of the unit. Other than by lease expiration, in the absence of express authority in the pooling clause, it would seem that the only means of terminating the unit is by consent of all the owners of an interest in the unit.

Declaration of pooling. Many lease-pooling clauses provide that pooling shall be effected by filing of record of an instrument describing the pooled acreage. When pooling clauses are silent as to means of acknowledging or declaring that a pooling has been effected, or when the clause is limited in instructions, the pooling declaration should, nevertheless, identify leases affected by the pooling, recite the legal description of the pooled unit, and state that the purpose of the instrument is to effect a pooling of the unit described in conformity with provisions contained in the respective oil and gas leases.

TO BE CONTINUED

About the Author

John H. Folks received his AB degree from Southwestern State, and his LLB from the University of Oklahoma. An employee of the Carter Oil Company more than 20 years, he has been Central Division Landman for Kansas, Oklahoma, North Arkansas, Missouri and Nebraska since 1951. Folks is third vice president of the American Association of Petroleum Landmen, and is a member of the Oklahoma Landmen's Association, Oklahoma State Bar and the Mid-Continent Oil and Gas Association. He has contributed to industry publications on subjects involving unit operations and contributions, and has lectured on these subjects at Land Institutes at the Southwestern Legal Foundation and the University of Oklahoma.

Here's how to . . .

Deepen small cased wells with cable tools

One Oklahoma operator has used cable tools to deepen a shallow well equipped with 4½-inch and 2½-inch casing. Total cost of the operation was approximately $895

By L. E. Collins, Petroleum Engineer
Collins Oil Company, Tulsa

PRESENT ACCEPTED methods of completing oil wells in relatively shallow areas with 4½-inch casing has presented several problems for producers. The most important problem has been to develop a feasible economic procedure for deepening such completions. Most producers and contractors considered deepening operations impractical in small pipe and usually recommend drilling a new hole to test deeper formations. However, Collins Oil Company has successfully deepened a small cased hole and tested lower sands by using cable tools. Total cost of the deepening operation was $895.

A hole cased with 4½-inch pipe may be deepened with cable tools if minimum bit tolerances are maintained. Bit diameter must be maintained at a minimum of 3¾ inches inside 4½-inch casing. Water and caving may be controlled with a hole full of water.

Essential information about deeper formations is exceedingly difficult to obtain in the Bird Creek, Okla., area when drilling in with a wet or cavy hole. To overcome this objection, 2½-inch casing may be run and cemented above the top of the zone of interest. Obtaining samples below the 2½-inch casing with a 1¼-inch diameter bailer presents no problem. Fluid fill-up, pressures, water-oil contact etc. can be determined as readily as in a larger hole.

The mechanics of completion in the small hole would be similar to methods used in larger holes. Fracturing and clean-out procedures can be followed in the conventional manner. Conventional slim hole completion pumping equipment can be used to recover the oil. Pumping or flow capacity is ample for most areas.

The economics of cable tool slim hole drilling and completion are attractive as compared to drilling a new well. A general rule of thumb used here is that if the estimated cost of deepening is not greater than the salvage value of well equipment, the operation should be feasible.

The production of a well in the Bird Creek field north of Tulsa, Okla., had declined to a point where operating costs were approaching income. The well had been producing from the Bartlesville sand at 1,150 feet. The top of the Burgess sand (underlain by the Mississippi lime) was located at approximately 1,400 feet. Both of these formations contained potential producing intervals.

Several adverse factors were present. A 4½-inch O.D. oil string had been set and cemented in the Bartlesville sand at 1,150 feet. The geology of the area was complex and the cost of drilling a new well to the lower formations was not justified on the basis of geological and production data available. Water in the bottom of the Bartlesville sand and a cave above the Burgess sand were known to exist.

A cross-section of the different pipe and bits required was used by rig personnel so that a close check could be maintained on tolerances at all times. A 3¾-inch bit coated with tungsten

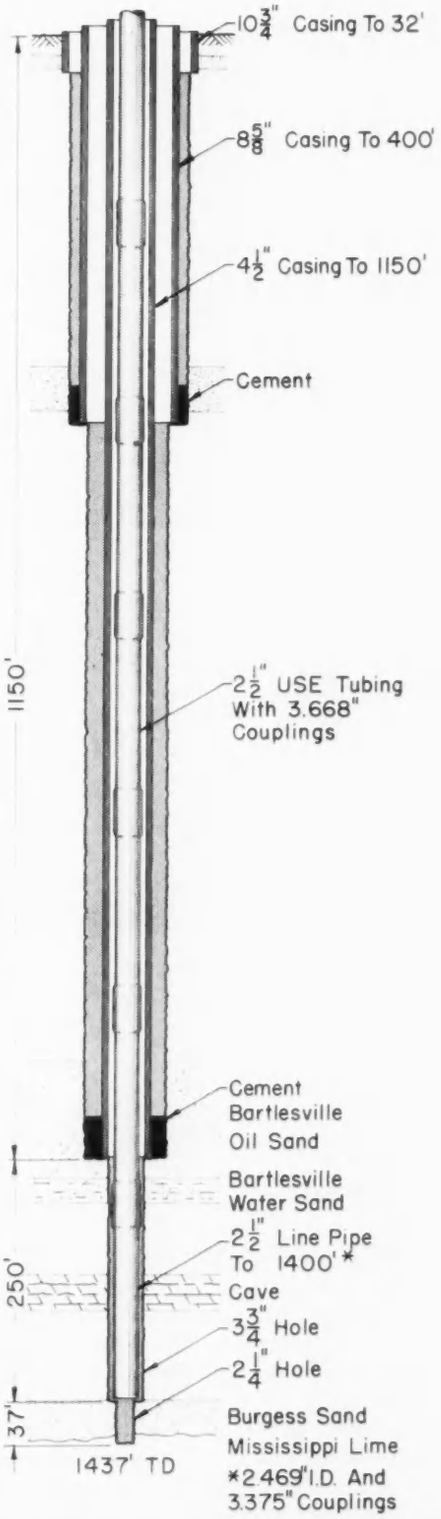


FIGURE 1—This schematic drawing shows the various hole sizes and casing strings used in deepening the slim hole completion.

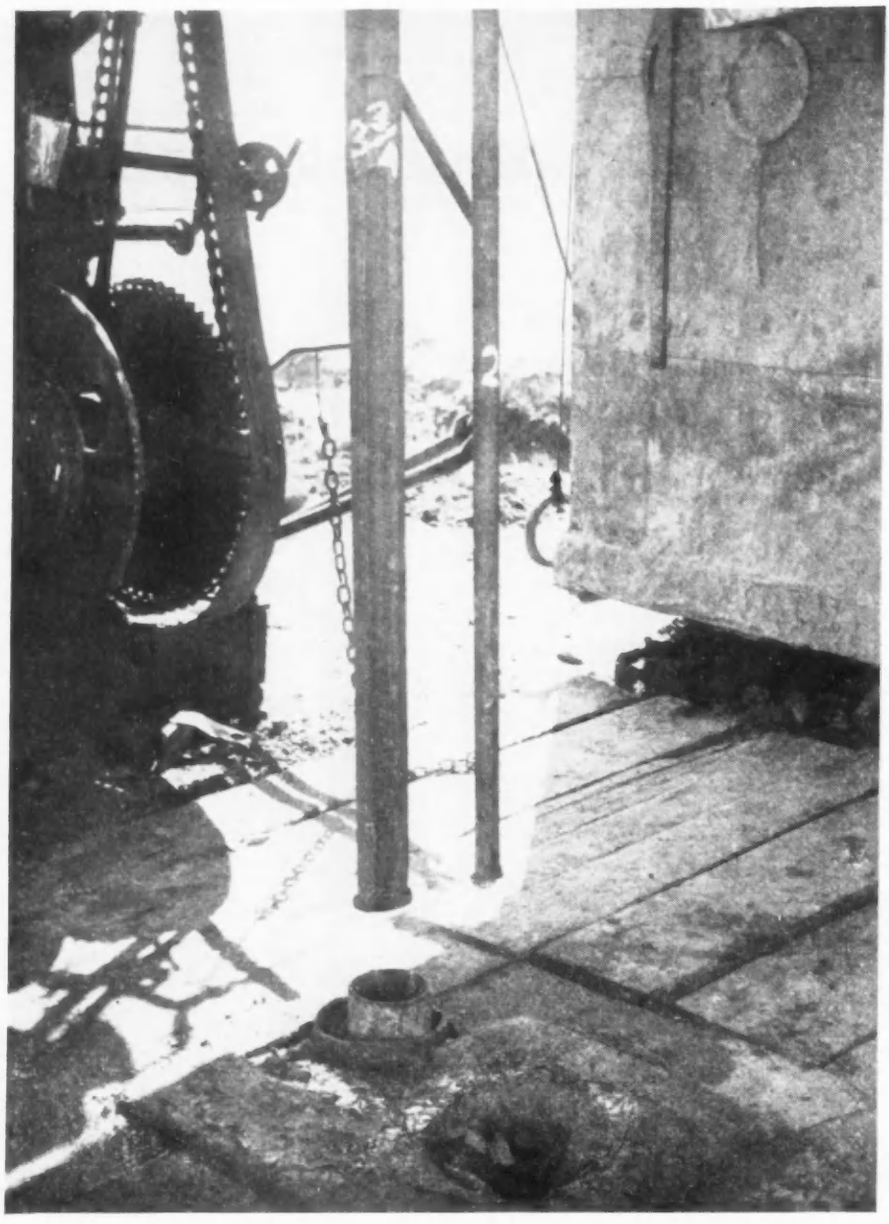


FIGURE 2—Here is a comparison of the cable tool bits used below the original 4½-inch casing string. The 3¾-inch bit (left) was used to drill 250 feet to the top of the Burgess sand. The 2½-inch bit (right) was used to drill the Burgess and the upper Mississippi lime after the 2½-inch casing had been set.

carbide was used to increase the drilling footage per bit and simplify maintaining a full gage bit.

After drilling through the Bartlesville formation the fluid level was allowed to stabilize at 300 feet. Bentonite was added to the drilling fluid at this point. Bit size was double checked on each run to maintain constant hole size. Only one bit was used during the entire operation. Drilling progressed at the rate of 35 to 45 feet per 8-hour period with no night work required. The top of the Burgess sand was reached successfully with no trouble.

In order to salvage the 4½-inch casing the operator parted the pipe above the original cement top. A 1,000 foot string of 2½-inch, Class B, heavy line pipe and 400 feet of 2½-inch upset tubing then was run to the bottom. The line pipe was run first since collar tolerance was greater and because 2½-inch upset tubing could not be ripped with cable tools if it were to be salvaged. Approximately 100 feet of the string was cemented since the salvage loss, if the well were dry, would be small compared to the cost of cementing after a pay zone was encountered. Five sacks of cement were used in the operation.

The following tools then were assembled: A swivel rope socket (for ¾-inch line), jars, stem consisting of two 1⅛-inch polish rods and a 6-foot bit dressed to 2¼-inch diameter. All tools joints were 15/16-inch API pin and box. Over-all length of the drilling tools was 28 feet. The swivel rope socket was used to assure a clean, round hole. The 2¼-inch bit (equipped with a 2-foot water course) was hard faced and dressed. The bailer used in the operation was 1¼-inch OD and 24 feet long. The advantage of maintaining tools to minimum tolerances was evident on one fishing job when a section of 1½-inch pipe with a welded coupling was used as friction socket to recover the stem and bit.

The hole was swabbed dry and the 2¼-inch bit installed. After reaching the Burgess, samples were taken every two feet. A very limey Burgess sand was drilled from 1,400 to 1,422 feet. No shows were evident in the Burgess sand. The Mississippi lime was topped at 1,422 feet. Scattered production in the area from the top of the lime prompted the operator to drill an additional 17 feet of hole. Due to the hardness of the Mississippi lime, tool joints were checked for fatigue following each run.

The hole was condemned dry at a total depth of 1,437 feet. Since the 2½-inch line pipe was on bottom the operator was able to rip apart and pull 1,300 feet of pipe. The 4½-inch casing, previously parted, was pulled and the hole plugged. Salvage value of the 4½-inch casing was sufficient to cover the cost of deepening and testing the lower intervals.

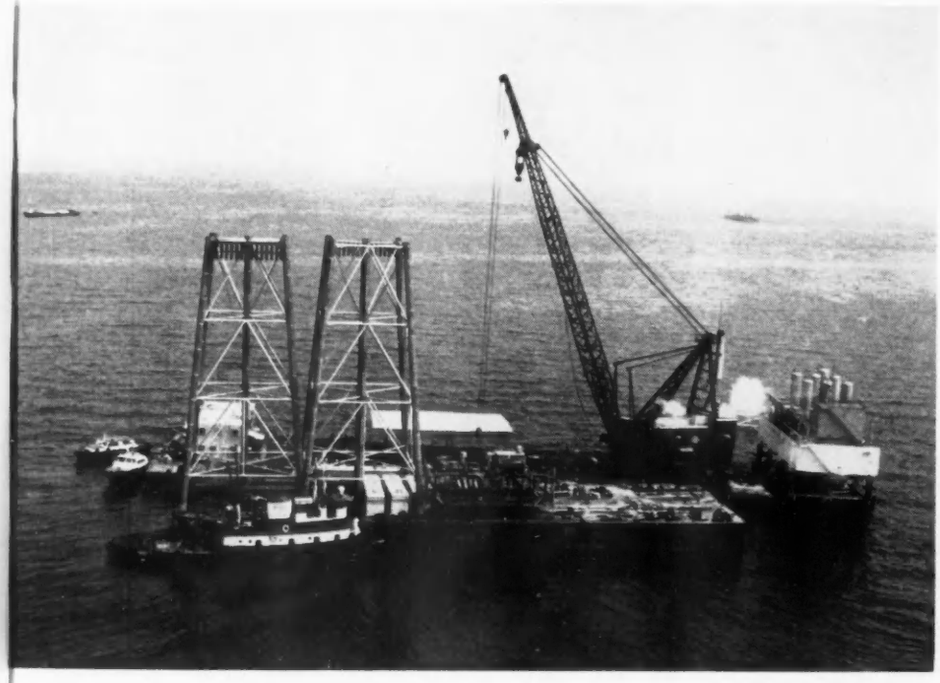
Although no commercial production was encountered in this case, it is felt that the operation was successful from an operating standpoint.

About the Author

L. E. Collins graduated from the University of Tulsa in 1952 with a degree in geology. He then joined Collins Oil Company, Tulsa working as a roustabout, driller, toolpusher and finally became a partner in the company and is now its petroleum engineer.

Aluminum drilling platforms prove successful in Lake Maracaibo

Two years of operation have demonstrated satisfactory corrosion resistance, more than adequate strength and ease of installation



Two aluminum template offshore drilling platforms are shown on a barge awaiting installation in Lake Maracaibo, Venezuela. The crane is lifting equipment onto an offshore flow station which also sits atop an aluminum template platform.

By Roy Striekert, Jr., Principal Engineer
Foreign Operations, J. Ray McDermott & Co., New Orleans

W. B. Moore, Jr., Director, Petroleum Market
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ALUMINUM OFFSHORE drilling platforms in use for more than two years in Lake Maracaibo are proving satisfactory in combatting corrosion, more than adequate in strength and easy to install.

While no aluminum platform has yet been relocated in the lake, the economy of such an operation is apparent.

Lake Maracaibo's warm brackish waters present one of the most severe corrosion problems ever encountered in a major crude producing area. The extreme corrosion stems from the high oxygen content and relatively high temperature of the water. These conditions prompted an investigation of the use of aluminum in areas subjected to continuing corrosive action.

Since drilling and production platforms imposed high corrosive problems, a new type jacket made of aluminum was designed and recommended for use with these structures.

The chemistry of aluminum is such that the light metal thrives on the conditions found in Lake Maracaibo. Oxygen reacts with aluminum to form a natural oxide layer on the surface of the metal. This oxide layer normally is not more than a few millionths of an inch in thickness. Actually, this layer is a distinct advantage because it protects the underlying aluminum from further oxidation. Aluminum oxide is an exceptionally stable material, resisting not only further oxidation but also attacks from most other materials.

An abundance of oxygen, naturally, helps maintain that protective oxide film.

Design of platforms. The platforms are supported structurally by driving steel piling through the aluminum jacket legs. This technique combines the corrosion resistance of the aluminum with the structural strength of the steel.

The inherent qualities of a jacket-type structure offer the following advantages:

• Maximum stability and strength in deep water marine structures.

Structures are braced continuously from above the water line down through the water and to the mud line. The stiffness of the jacket column increases the effectiveness of the steel piling and affords maximum structural stability. From actual reports from the oil operators in Lake Maracaibo, these aluminum jacket type drilling structures vibrate very little during drilling operations and experience no detectable deflection as a result of wind and wave conditions.

Case histories can be cited in which large marine cargo barges, in the

FIGURE 1—Gussett plates are shown being welded to the cross members of the aluminum template.

FIGURE 2—A 50-ton concrete slab is used to push the aluminum template into the bed of Lake Maracaibo and level the structure off. During this operation, the weight of the slab rests on a temporary deadweight frame atop the aluminum template.

heights of a storm on Lake Maracaibo, have collided with these aluminum jacket type structures and inflicted only minor damage to the boat landing on the structure. The remainder of the structure, in such instances, proved to be completely intact and suffered no indicated damage.

• Rapid installation of the structures.

The structure can be installed in the lake complete with the drilling rig and equipment in operation, within 36 hours after the oil operator has given approval to proceed with construction.

• Salvage potential.

In the case of a dry hole, an aluminum structure can be salvaged and reinstalled at a new drilling location quickly and economically. The structure is salvaged by cutting off the steel piling below the bottom of the jacket after the removal of the drilling rig and deck section. The structure then can be lifted and moved to the new location where smaller steel piles are driven within the original piling. The final step is to replace the deck section and drilling rig to its original position on the structure.

The metal selected for fabrication of the platform was aluminum alloy 6061-T6. This alloy is composed of aluminum (97.90), magnesium (1.00), silicon (0.60), copper (0.25) and chromium (0.25).

All the 6061-T6 aluminum used in the templates is given solution heat treatment and a precipitation heat treatment before being shipped to the fabricator.

Structurally, the aluminum jacket is made up of four legs, or columns; a center conductor column and vertical and horizontal braces for additional strength. The legs of the structure and the conductor guide are 34 inches outside diameter, with .375-inch wall thickness. The legs are made from rolled plate. The vertical bracing is of 10¾-inch OD extruded pipe of .365-inch wall thickness while the horizontal bracing is of 8⅝-inch OD extruded pipe of .322-inch wall thickness. Each of the joints in the jacket is reinforced with a special extruded tee shape section to gain weld strength and structural continuity at the panel points.

Most of the templates have been about 111 feet in height, weighing about 34 tons.

In position in Lake Maracaibo, the aluminum-template platforms are supported by 30-inch OD steel piles driven down through the jacket legs, and a 30-inch OD steel conductor pipe also is driven down through the aluminum center conductor column. To guide the piles and conductor pipe through the aluminum jacket, there are four spacer insulators in each column. These insulators are made up of a steel band and runners completely insulated from the aluminum column by neoprene rubber.

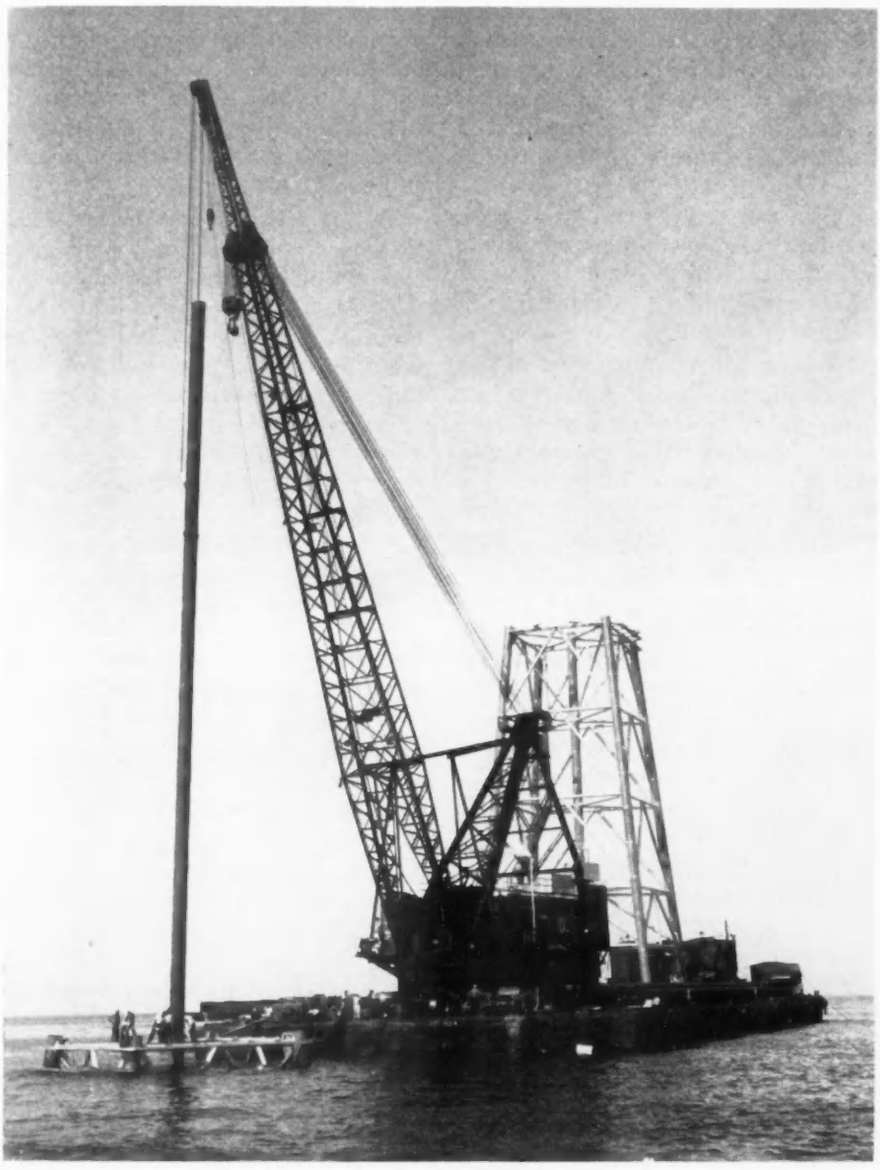


FIGURE 3—A steel piling being lowered into one of the aluminum template columns.

About the Authors

Striekert

Moore

Roy R. Striekert, Jr., a native of Houston, received his B.S. degree in civil engineering from the A & M College of Texas in May 1952. Striekert joined J. Ray McDermott & Co., Inc., in May 1954. He was appointed Principal Engineer, Foreign Operations for McDermott in June 1958. Striekert received his M.S. degree from Tulane University in September 1958. He resides in New Orleans.

W. B. Moore, Jr., a native of Jackson, Miss., received his master's degree in chemical engineering from the University of Louisville in 1947. For the next two years he was chief engineer for the university's Institute of Industrial Research, after which he joined the technical service department of Reynolds Metals Company. In 1952, he became manager of Reynolds' chemical and petroleum market, and in 1958 was promoted to the newly-created position of director of the company's chemical, petroleum and farming markets. He is a member of the American Petroleum Institute and a number of professional associations. His office is at the Reynolds headquarters in Richmond, Va.

At the bottom of each jacket leg, there is a continuous rubber ring packer. This packer is displaced by the pile as it is driven through the bottom of the jacket and will have a tight seal to keep any excess mud from coming up into the annulus between the jacket and the pile. It also forms a seal at the bottom of each leg to aid in the grouting operations.

One of the requirements of the design of the platform was the prevention of galvanic corrosion between the aluminum template and the steel piling. The insulating spacers in the four legs and the center conductor guide already mentioned serve this purpose. In addition, a special grout is poured in the annulus between the aluminum and the steel legs to maintain permanent separation between the dissimilar metals. This grouting process will be described more fully in connection with the installation procedure for the platforms.

Fabrication of templates. The structures were to be completely welded. Fabrication of the platforms did not involve any welding equipment or techniques which were new to the aluminum industry. But it did involve considerable modification of welding equipment and techniques which were new to the fabricating personnel, since previously most of their work had been done in steel.

A welding engineer prepared welding specifications and procedures for the project, personally trained the welding crews, and spent some time on the job site inspecting completed welds. Under this program, the fabrication personnel quickly achieved the required proficiency in welding of aluminum.

Aluminum alloy 4043 filler wire was used in all welds. Semi-automatic inert-gas consumable arc welding equipment was employed.

Butt and fillet welds are the only types permitted. Butt welds are employed only in splicing pipe or structural members. Fillet welds are made along the edges of extrusions and are made longitudinally along the major axis of the pipe. Lap welds are not used in the fabrication of these templates.

In the fabrication of pipe braces

and columns (Figure 1), no two splices are ever made closer together than 1½ feet, and there are never more than three splices in a 10-foot section of pipe. Every butt joint that does not fall at a panel point is reinforced on the exterior by three doublers cut from the same diameter pipe and shaped to conform to the contours of the extrusions.

Inspections of all welds are made regularly throughout fabrication. An X-ray shot is taken from the first 10 lineal feet of production welding performed initially by each welder. On butt welds or primary structural welds, one shot is taken for each 50 feet of production welding. On fillet welds or secondary welds, one shot is taken for every 100 feet of lineal welding, and for a check of the welders' proficiency, each weld is marked by his personal stencil for identification purposes.

Installation procedures. Upon completion, the prefabricated structures are set upright on barges, secured in position and towed to Venezuela. Four structures can be accommodated on one of the barges, complete with necessary piles, conductor pipes, deck sections and miscellaneous installation equipment.

The utilization of large ocean going barges makes possible this economical delivery of the platforms.

One of the advantages of the aluminum jacket platform is its relative ease of installation. The first such platform was installed in five days. After this initial experience was gained, subsequent structures—plus the complete drilling rig—have been installed in as little as 36 hours. This compares with about 25 days time for installation of concrete pile structures.

Preparing for installation, four steel deadload weights (Figure 2) are placed on the sides of the structure, with cable slings attached for later removal. These weights are necessary because the template has an excess buoyancy of approximately 22 tons when submerged to its normal installation position with the columns open and all of the braces sealed. When the jacket is lifted off the deck, wooden plugs are inserted in the bottom of the four jacket legs and the conductor column. The jacket is then set overboard into its proper location.

After the jacket is set, the columns will flood with water, but the wooden plugs will keep out all excess mud. These plugs will be knocked out when the piles are stabbed and driven, but the steel deadweights are removed from the structure after the grouting operations.

It is necessary to apply concrete deadload blocks to the top of the jacket during installation to level it off and to push it the desired 15 feet into the mud on the bottom.

Since the piles are battered in two directions, the spacer insulators are made up with four sections of runners in the diagonal or interior quadrant of the column. This assures that the pile is supported by four of these spacer runners during the stabbing and driving operations.

The piles are designed for a penetration which has ben predetermined by careful soil analysis of each of the locations at which the structures are installed. These piles are driven according to normal practices to a depth which will support a load of approximately 280 tons.

When the piles and conductor pipe are driven, the special grout is poured in the annulus between the template columns and the steel piles to provide permanent electrical insulation (Figure 3).

Approximately 150 psi of bond exists between the aluminum jacket and the grout and between the steel pile and the grout. This indicated bond strength is far in excess of the bond needed for structural stability.

This grout is excellent for preventing galvanic current flow between the aluminum jacket and the steel pile. Resistivity of the grout increases directly with time of setting and age of the grout, and data show that almost complete insulation from galvanic currents can be anticipated almost immediately after the insulation of the structure.

The alkaline solution of freshly poured grout reacts with the aluminum to generate hydrogen gas. This gas, while not appreciably affecting the bond strength between the grout and the aluminum, seemed to pose a construction problem. If enough of the gas were generated and trapped at some elevation below the top of the jacket leg, this gas pocket could force the grout back out of the leg or, if not, create large voids in the annulus and prevent the required continuity of grout. To eliminate this reaction at the interface of the aluminum jacket, the interior of the 34 inch aluminum columns is coated with a tar base paint. Tests showed that this coating did not affect the bond strength between the aluminum and the grout.

During and after installation, careful checks are made to verify that complete electrical separation between the aluminum and steel has been achieved. This is done by taking readings of the electrical potential difference between the two metals. Measurements of this potential difference are made when the piles are inserted, when the piles have been driven, and again after grouting. Readings are taken again after the wells have been drilled, and at regular intervals thereafter to insure there is no accidental electrical contact between the template and the piling.

The results of these readings gave assurance that the design features and operational procedures for preventing the possibility of galvanic corrosion were successful.

The aluminum structures have as a component part a 30 foot x 30 foot prefabricated steel deck section, complete with galvanized grating working surface and stabbing points on each of the corners to aid in erection. The four steel piles in the template are cut off in a horizontal plane at the correct elevation, and the deck section stabbing points stab into the piles. The piles are cut off to the four bottom corner base plates of the deck section.

After the installation of the boat landing, barge bumpers, and stairway to the deck section, the drilling equipment then is installed in the same manner as are those on offshore drilling structures in the Gulf of Mexico.

The aluminum drilling structures have shown remarkable resistance to the corrosive waters of the lake. Aluminum test samples to simulate the exact conditions of the erected structures were installed on the first four aluminum platforms. These test samples have been inspected periodically, with the most recent inspection being in October 1959. This latest inspection covered an installed time of two full years. This check gave the indication that these aluminum structures have a life expectancy of more than 50 years. **—The End.**

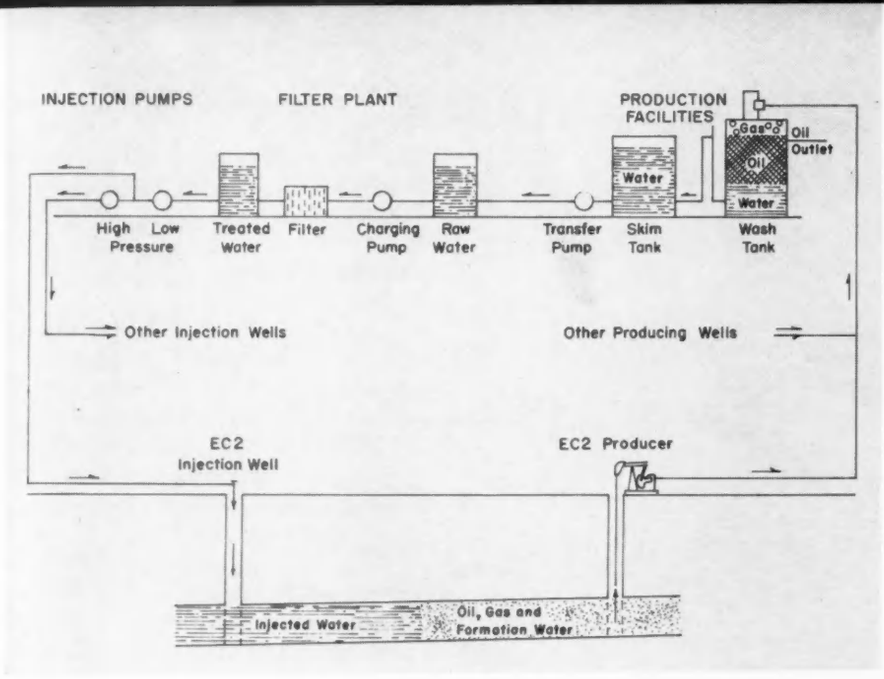
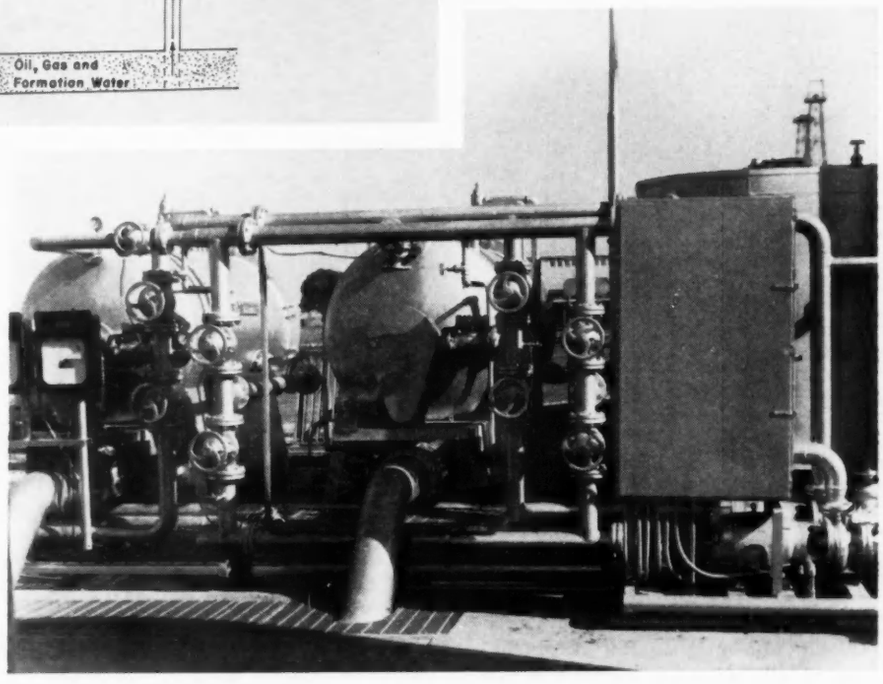


FIGURE 1—Here is a schematic flow diagram of the Dominguez field waterflood project. Water is pumped automatically from the skim tank to the filtering facilities.

FIGURE 2—These skid-mounted filter units (shown below) are completely valved and piped and are equipped with electric motor-driven charging pumps, volume recorders and the filters proper. Controls are housed in the metal cabinet at right. Due to the unitized design, a minimum of time and work is required in hooking up this equipment.



Unique skid-mounted filter package, centralized water injection system and automatic controls increase operating efficiency, reduce costs

In California — new waterflood features unitized equipment layout

By J. A. Pryor
Mechanical Engineer
Shell Oil Company
Long Beach, Calif.

SHELL OIL COMPANY has recently completed a new waterflood plant in the Dominguez field, California. The installation was designed with economy and ease of operation, maintenance and expansion foremost in mind.

Unusual features of the plant are:

- Minimum raw and clear water storage
- Skid-mounted, packaged filter units
- Electric motor-driven high-pressure, centrifugal pumps are used to inject water.
- Centralized injection well manifold
- Waste disposal system which recovers and uses most of the filter backwash water for injection purposes.

The success of waterflooding in Dominguez field influenced Union Oil Company of California, Shell Oil Company and Dominguez Oil Fields Company to start a cooperative flood in the East Central Block of the Second Zone. This zone produces 29 gravity crude from an average of 165

Complete details of the Dominguez field filter plant hookup . . .

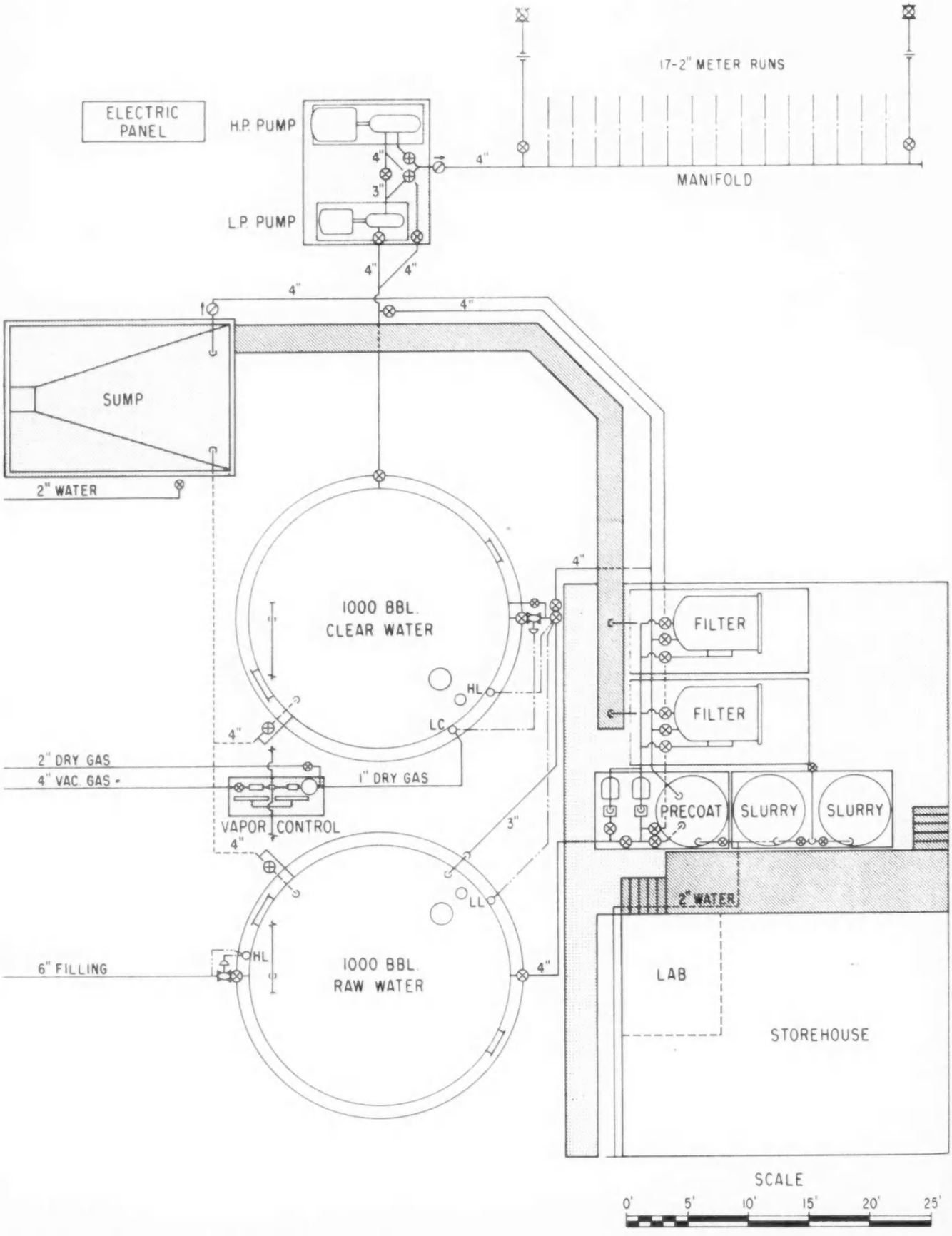


FIGURE 3—High and low liquid level controls as well as the vapor control equipment are shown on the water storage tanks. Also, note that the injection pumps are manifolded for individual or series operation.

feet of net sand at an average well depth of 4,600 feet. Shell has designed, constructed and initiated the operation of a new 10,000-bpd capacity waterflood plant for flooding of this zone.

Water supply is the saline water produced from the eight zones of the Reyes lease, which Shell operates. Approximately 11,000 bpd of water are gathered from two 3,700-barrel and two 6,300-barrel lease wash tanks into a 5,000-barrel skim tank (Figure 1).

Water is transferred from the skim tank through a 3,900-foot, 6-inch line to the plant site by an electric motor-driven centrifugal pump. The 15-hp motor is started automatically every 15 minutes by a time-clock-operated switch. In operation, a diaphragm-operated valve on this line at the waterflood plant is closed by action of a high level float switch on the plant 1,000-barrel raw water tank. The high pressure in the line due to this valve being closed operates a pressure switch at the transfer pump which shuts off the pump motor. A high level-activated switch on the skim tank also will automatically start the transfer pump before any water is wasted by overflowing into the disposal system and a low level-activated switch on this tank will shut the pump off before it loses suction pressure.

The plant raw water storage tank is a 16-foot, 1,000-barrel, 10 gauge welded steel tank, coated internally with a 15 mil thickness of a coal tar-epoxy type resin for corrosion resistance. A vapor control system is installed on the water storage tanks at the plant to prevent the air sensitive water from being affected. When the tank is filling, a vapor pressure-operated diaphragm valve opens to collect the vapors into the lease vacuum gas system; a similar vapor pressure-operated valve opens to introduce dry gas into the tank when the tank water level is being lowered. A safety, vapor-sealed overflow to the backwash pit also is installed on each of these storage tanks.

A 20 x 30-foot, 10-foot high rigid frame, galvanized sheet steel covered building was built for storing the diatomaceous earth filter aid, asbestos-wood precoat materials and water treatment chemicals. A small 8-foot by 10-foot office and laboratory was incorporated into the building to provide a convenient place to make water quality tests and to keep plant records.

The floor of the building was constructed at a convenient level for the plant operator so that he is provided with a safe working level from the storage area to the filter precoat slurry tanks. In this manner, safety is assured while carrying or unloading sacked material into the tanks.

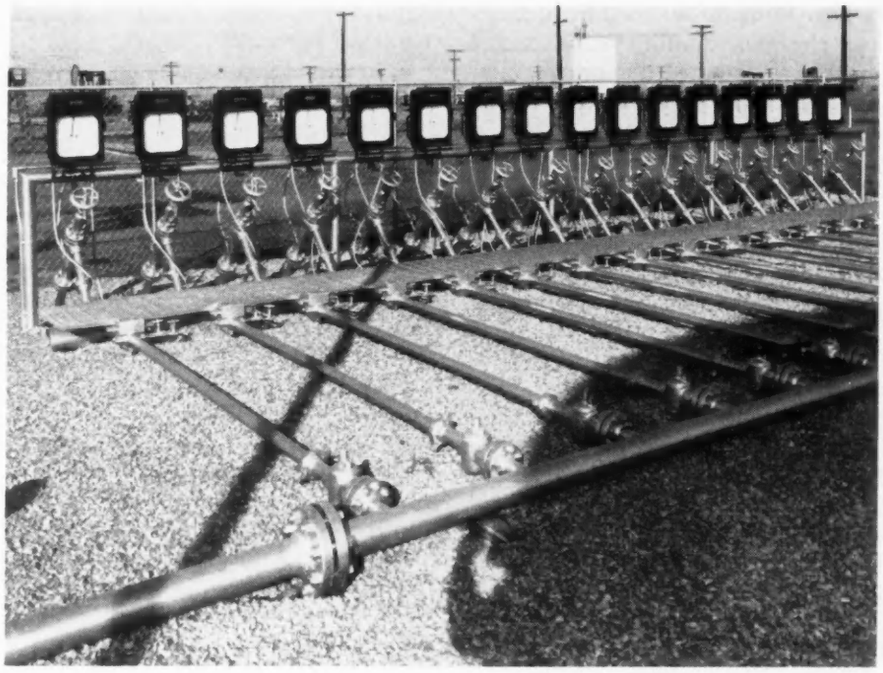


FIGURE 4—Adjustable flow control valves are used to control input volumes to individual injection wells from the centralized manifold. Note that each input line is equipped with an orifice meter. Also, flow control valves are mounted conveniently so that input rate changes can be observed directly on the meters as the valves are adjusted to the new rate.

Filter packages. The filter package, designed for ease of expansion or replacement and maintenance, consists of four skid-mounted units. Two of the skids each contain a 500-square foot surface area filter; one holds the precoat tank and the charging pumps and the fourth skid unit holds the two slurry tanks and the slurry feed pumps. The entire package was shop fabricated so that it required only field connections for raw water inlet, filtered water outlet, filter drain and electricity for its operations. The unit (Figure 2) was designed so that all operating valves (with the exception of the slurry feed valves) are easily visible along the front of the skids and the backwashing of the filters can be performed with a minimum of confusion. Filters are equipped with a corrosion-resistant copper-nickel alloy shell and horizontal leaf-type filter elements. The five-ply filter leaves consist of three copper-nickel alloy screens and two fine mesh stainless steel outer screens. A precoat of asbestos-wood pulp mixture followed by diatomaceous earth presently is used. A slurry of diatomaceous earth is added to the raw water as a filter aid. Each filter has a separate slurry tank and pump for filter aid volume control.

Two 15-hp electric motor driven 3 x 4-inch close-coupled centrifugal pumps (Figure 2, right) are mounted on the precoat tank skid. One pump usually feeds both filters. The second pump is used for backwashing and precoating the filters and as a standby filter feed pump.

The flow through the discharge line of each filter is measured by orifice meter. A bellows-type, 7-day chart differential pressure recorder is used. A two-pen, 7-day chart recorder is used to record the pressure drop across the filters.

All but the filter drain valves on the filter package are manually-operated, synthetic rubber diaphragm seat valves. This type is used to withstand the abrasive action of the filter aid materials.

The clear water storage tank, with the exception of controls, is of the same construction as the raw water storage tank. Tank size was determined by the time required to backwash one filter. A little over two hours usable storage time was desired to allow some margin of safety over the usual 45 minutes backwash time.

The filtered water from the filter

package flows through a 3-inch, three-way electro-hydraulic valve and a 3-inch, gas operated diaphragm valve into the clear water storage (Figure 3). When the electro-hydraulic valve is de-energized, the filtered water is by-passed back into the top of the raw water tank. A high level float-operated switch on the clear water tank, a low level float-operated switch on the raw water tank or a manual switch will de-energize this valve. Generally, the plant operator will use the manual switch to by-pass the first water filtered after a new precoat and all water filtered directly from the backwash sump. The low level float-operated switch on the raw water tank will keep the filters on stream even if the raw water supply fails. The 3-inch diaphragm-operated valve on the line from the filters to the clear water tank is used to control the flow in the line. A high level controller on the clear water tank regulates gas pressure to the diaphragm valve. When the level of water in the tank is low this valve is wide open but when the tank is almost full the valve throttles the volume of water being filtered to equal the volume of water leaving the clear water tank. An open by-pass line (1-inch) around this control valve limits the minimum filter flow rate to prevent the filter cake from falling off the filter screens. If injection pumps are stopped, the water level will rise until the high level float switch de-energizes the electro-hydraulic valve and filtered water is by-passed to the raw water tank.

Injection system. Pressures experienced in the previous flood were much lower than expected so that design pressure requirements for the plant were lowered from 2,000 psi to 1,000 psi surface pressure. This reduced design pressure made centrifugal pumps economically attractive.

The low pressure injection pump is a 125-hp, 2,400-volt electric motor driven two stage, corrosion-resistant aluminum bronze constructed, 3 x 4 inch centrifugal pump which will handle 10,000 bpd of water at 350 psi pressure. The high-pressure injection pump is similar, except that it has four stages and is powered by a 200-hp electric motor. It will handle 10,000 bpd of water at 750 psi. Suction and discharge piping (Figure 3) is designed so that pumps can be used individually, or in series. Maximum capacity in series is 10,000 bpd at 1,100 psi pressure.

A low level float-operated switch on the clear water tank will shut down the pump or pumps in service and the same pump combination is started automatically by a high level float-operated switch when the clear water storage tank is nearly refilled.

The centralized injection well manifold is connected directly to the injection pump discharges. The shut-off valve, meter run and adjustable flow control valve for each well in the flood are located in this central manifold (Figures 3 and 4). The centralized manifold was selected in preference to a two pressure trunk distribution system since line costs were about equivalent and the centralized system permits the plant operator to control all wells at the plant without having to drive to each injection well site. Adjustable flow control valves were used for reasons of economy and because they had the advantage of a full range of control.

The volume recorder is composed of a bellows-type differential pressure element and a 30-day electric clock-driven chart. A pressure element is used to record the pressure downstream of the 2-inch adjustable flow controller on each well. The 30-day chart requires one-fourth as many changes and readings as 7-day charts and small pressure differences which occur over the 30-day period, are more obvious.

Backwashing. Slurry and solids backwashed from the filter screens are drained through a sloped concrete trough (Figure 3) to a 12 x 18 x 6-foot deep sump. The sump bottom is sloped to a 2 x 2 x 2-foot suction pit at the far end to permit easy cleaning. A vacuum truck is used to clean the sump.

Most of the backwash water in the sump is pumped back into a filter just before the filter requires backwashing. The precoat pump is used to pump this water and the three-way electro-hydraulic valve always is manually controlled to recirculate this water (after filtration) back into the raw water tank. In this manner the backwash water always is double-filtered before it is injected into the wells. There is no water disposal line near the plant so this system saves considerable trucking costs.

Iron counts, sulfate-reducing bacteria counts, corrosion detecting probes and millipore filter tests are the tools used to determine injection water quality. Tests now are being made to determine the most effective inhibitor to reduce the present indications of minor corrosion in the distribution system.

The filter cycles have been very favorable (averaging over five days) and one operator working five 8-hour days per week has handled the entire plant filtration and injection operation. During the hours that the operator is off duty, lease pumpers check the plant on their regular rounds. The water level of each tank can be checked by observing externally mounted gauge boards. Also, warning lights (low level operated float switches on each tank) can be seen from the pumpers' truck or the nearby main lease office.

If expansion becomes necessary, two additional filters can be aded within the present site to increase plant capacity to 20,000 bpd. In addition, there is adjacent land available to enlarge the entire plant and increase its capacity to 40,000 bd.

The initial Dominguez field waterflood plants were designed, constructed and operated by Union Oil Company of California. Their experience and assistance has been extremely valuable in the design of this new plant. —**The End**

About the Author

J. A. Pryor is a Production Department mechanical engineer in the Los Angeles Basin division of Shell Oil Company. A graduate of the University of Southern California in mechanical engineering, he has worked in the Pacific Coast area of Shell for 11 years. An officer in the Naval Reserve, he has had five years of active duty, the last two being from 1952 to 1954 during the Korean conflict. He has been active in corrosion and waterflood projects in Southern California for the last five years. He is a member of the National Association of Corrosion Engineers and the Study Committee on Fluid Injection, a subcommittee of the API Pacific Coast District Committee on Production Practice.

in the San Juan Basin . . .

New discoveries spark Dakota play in northern New Mexico

Despite extensive exploration and development work, a large potential oil and gas area remains to be drilled

NEW MEXICO's portion of the San Juan Basin continues to be an area on the move. Reasons:

- Unusually high wildcat success ratio. Of 133 wildcats drilled last year in northern New Mexico, 48 discovered gas—16 discovered oil, for a 48.1 percent success ratio. (Under New Mexico law, a well drilled 660 feet from a field boundary defined by the State is a wildcat).
- Increasingly widespread production from Dakota sandstone (Upper Cretaceous), below the Pictured Cliffs and Mesa Verde pools.
- New Gallup oil production at the east side of the Blanco area in San Juan and Rio Arriba counties.
- Rapid development of the Chimney Rock-Horseshoe Canyon-Verde area west of Blanco.
- Even though development work is progressing rapidly in northern New Mexico, there still remains a large prospective oil and gas area that has had comparatively little exploration.

However, despite this promising outlook, total drilling for the basin will tend to flatten out from year to year and be maintained at a steadier level unless a good-sized oil field is opened. In the past, drilling flurries came when sharply increased demand for gas was plainly in view, and when promising oil fields were being developed.

Foreseeable demand for gas apparently will not show the big bulge created in the past by construction of new pipe lines, notably the Pacific Northwest line. Dakota production may thus be under somewhat less demand pressure than was production from Pictured Cliffs and Mesa Verde.

Nevertheless, demand will continue to increase if current interest in supplying future gas needs of the West Coast is to be accepted as a proper index.

6,000 wells in 10 years. More than 6,000 wells have been drilled in the San Juan Basin area of New Mexico since 1950. Annual drilling rates ranged from 66 in 1950 to 1,007 in the peak year of 1958.

Initially, San Juan Basin drilling was almost all for gas. The development of the general Blanco area accounted for the major portion of the completions. Most of this work was to Upper Cretaceous formations—Pictured Cliffs and Mesa Verde.

Since 1955, oil wells have made up an increasing percentage of San Juan drilling. Bisti, the Chimney Rock-Horseshoe Canyon-Verde area, and several other smaller fields have been discovered and developed since 1955.

Major Dakota play. Of 48 gas producers completed as wildcats in the Basin during 1959, 42 were listed as discoveries in Dakota. Most of these are concentrated east of the axis of principal developments to shallower formations throughout the Blanco area. This follows the earlier predictions made in support of pipe line projects to serve the Basin.

Last year's Dakota discoveries were concentrated in an area bounded by 4w-13w, 24n through 31n (see map). This does not contain all the area's work to this deeper formation by any means, but is the focus of Dakota work. It lies generally along the east side of the Blanco area.

A few pools within this area have had enough development to indicate substantial size. This is particularly true in 26n-27n-28n, 10w and 11w, San Juan County.

Leasing is stable. Leasing is comparatively stable throughout the cen-

"133 wildcats were drilled in northern New Mexico during 1959, resulting in 48 gas and 16 oil producers, for a 48.1 percent success ratio."

"More than 6,000 wells have been drilled in New Mexico's San Juan Basin area since 1950."

Baker's New Snap-Set Duals

-the packers that are bringing single-zone control and simplicity to dual completions

Many operators are coming to feel that the best dual-zone hookup is a modern dual-string hookup. A Baker dual-string completion approaches the control and simplicity (and the flexibility) of a single-zone completion. It is the nearest possible equivalent to two single-zone completions in one well.

What makes this possible? Mainly the development of better upper retrievable packers—Baker's new snap-set duals. They are practical and reliable—and so are the Baker hookups they're used in. Operators all across the country are commenting on their impressive performance.

THE IMPORTANCE OF TWO TUBING STRINGS

Producing through tubing—whether from one zone or two—has its virtues. It protects the casing from corrosion and pressure damage. It encourages easier flow and longer flow, discourages gas separation and loss of natural lift. It makes it easier to run instruments and workover tools, makes artificial lift easier.

It is clear that dual-string production can make the economic success of many wells—provided the hookups are practical. That's where Baker's new dual packers come in.

THE IMPORTANCE OF SIMPLICITY AND FLEXIBILITY

A good dual-string hookup is a simple one. Complexity never had a virtue, never had a payout—especially in a dual completion.

Simplicity is important because the hookup must be reliable and flexible. The key to these things is the upper retrievable packer. That is why Baker has explored every opportunity to simplify the design (see opposite page) of these rugged new dual packers.

A good dual-string hookup is a system—not a random assemblage of parts. This system must satisfy certain requirements. Many of the requirements depend on the upper retrievable packer.

First, both upper and lower packer must pack off and stay packed off. Nothing defeats the economics of a dual completion so readily as a packer that leaks.

Other requirements are equally important. Is it easy to set and unset the upper packer? Is spacing out simple? Can packers be tested before displacement? Can mud be displaced and zones washed while flanged up? Is there provision for simplicity of workover? For artificial lift?

It's all a matter of costs and returns. Baker dual packers were conceived to make dual string completions a paying proposition—and that is what they are doing. With these new packers, dual-zone production has come of age.

RELIABILITY IS BAKER'S STRONG SUIT

Any man who knows the Baker reputation will realize there's a lot of packer and squeeze tool experience behind these new retrievable packers. In fact, Baker's knowledge of these things is unprecedented.

Baker packers have proved themselves in thousands of wells the world over, holding for years, in many cases, against high pressures and withering temperatures. That's a tough proving ground for packing, slips, setting methods, and the like. That is one reason Baker packers are tough and reliable. Reliability is Baker's strong suit.

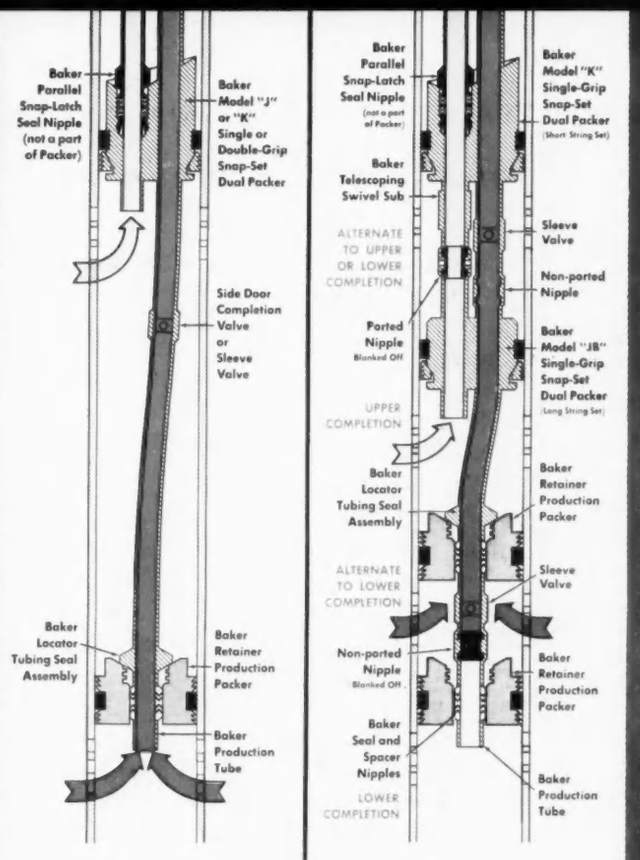
BAKER RETRIEVABLE SNAP-SET DUAL PACKERS

THERE ARE TWO BASIC MODELS. Each comes in a single-grip and a double-grip version. (Double-grip version has hydraulic hold-down buttons that tighten grip on casing when pressure from below increases.)

PICTURED IS MODEL J (Product 756-J) in the single-grip version. Model J is long-string set. You set it by setting down long string against the resistance of the stinger installed in lower retainer packer.

MODEL K ISN'T SHOWN. Model K (Product 756-K) is short-string set. You set it by setting down short string against resistance of long string. This permits either (a) keeping long string in natural tension, or (b) running another retrievable packer below the Model K.

A close look at Baker Dual-String Hookups - and at the Baker packers and accessories that make these hookups simple, flexible, and practical


Baker Parallel Snap-Latch Seal Nipple (not a part of Packer)
Baker Model "J" or "K" Single or Double-Grip Snap-Set Dual Packer
Side Door Completion Valve or Sleeve Valve
Baker Locator Tubing Seal Assembly
Baker Retainer Production Packer
Baker Production Tube
Baker Parallel Snap-Latch Seal Nipple (not a part of Packer)
Baker Telescoping Swivel Sub
ALTERNATE TO UPPER OR LOWER COMPLETION
Ported Nipple Blanked Off
UPPER COMPLETION
Baker Locator Tubing Seal Assembly
ALTERNATE TO LOWER COMPLETION
Non-ported Nipple Blanked Off
Baker Seal and Spacer Nipples
LOWER COMPLETION
Baker Model "K" Single-Grip Snap-Set Dual Packer (Short String Set)
Sleeve Valve
Non-ported Nipple
Baker Model "JB" Single-Grip Snap-Set Dual Packer (Long String Set)
Baker Retainer Production Packer
Sleeve Valve
Baker Retainer Production Packer
Baker Production Tube

LEFT, STANDARD DUAL STRING HOOKUP. It is simple and basic.

RIGHT, LOW COST MARGINALS. This hookup lets you pick up two marginal zones for little more than cost of two extra packers. Marginals can be produced as alternates to primary zones when allowables are reached.

TWO SIMPLE PACKERS. Basic to a good dual-string hookup are two types of packers. At bottom, to provide the vital separation of zones, a Baker Retainer Production Packer – the most respected retainer packer in use today. At top, to provide the flexibility that makes dual completions practical, a Baker snap-set dual – the new retrievable packer that is proving itself to the most demanding of operators.

UPPER DUAL PACKER: IT'S EASY TO SET AND RELEASE. When you set a Baker Snap-Set Dual Packer there's no ball dropping, no rotation, no pressuring. You set it by setting down minimum weight. To unset, you pick up. It's just that simple. (One model is long-string set, the other is short-string set. See opposite page.)

WHAT SNAP SETTING DOES FOR YOU. It's the snap-setting feature that lets you set and unset the Baker dual packer any number of times – for spacing out, testing packers, displacement, etc. There's nothing final in the latch action – no shear pins, for instance, to burn your bridges and make setting an action from which there's no turning back.

HOW CAN YOU BE SURE SHORT STRING IS IN PACKER? Baker makes a special snap-latch seal nipple that seals off the retrievable short string in sealing bore of upper dual packer. This nipple snaps into packer and holds firm. So to make sure it's seated, just stab in and pull back slightly.

YOU CAN COMPLETE FLANGED UP. Using a side door completion valve, or sleeve valve, or other method, you can displace mud and wash in both zones with well head flanged up. You keep the well under complete control.

WHY BAKER DUAL PACKERS HAVE LARGE BORES. Big bores through upper packer offer a real advantage. Packer bores should be as big as the tubing bores so instruments and workover tools won't hang up. In Baker dual packers the bores are that big – there's no restriction, no necking down. How large are the bores? A dual packer for 7″ casing is full-opening for two strings of 2⅜″ tubing. What makes this possible is simplicity of design. There are no elaborate seals, valves, or other mechanisms to restrict the packer bores.

HOW SQUEEZE TOOL EXPERIENCE CONTRIBUTED TO THE DESIGN OF SUPERIOR PACKING ELEMENTS. Baker dual packers have three packing elements. They're short and rugged – and the upper and lower elements are harder than the center element. It's a design similar to that used in Baker's high performance retrievable squeeze tool – the Full-Bore Cementer, which has been used in thousands of high pressure cementing, frac, and testing operations. The design accomplishes three things: It offers (a) positive packoff with (b) minimum set-down weight, and (c) permits the packer to be repositioned or retrieved easily, because it prevents packing element extrusion without resorting to the metallic back-up rings that sometimes defeat retrievability.

WHAT THE PICTURES CAN'T SHOW. The pictures can't show the stored energy in the tubing string and what it does to maintain packoff. Some dual retrievable packers depend on trapped pressure for a static packoff. In Baker's opinion that isn't adequate, and may easily lead to leakage. It fails to compensate for any packing element extrusion that occurs – and there is usually some. The Baker method does compensate. In a Baker dual packer the stored energy in the tubing string (energy due to set-down weight) acts like a spring to keep the packing elements under a dynamic compression.

SLIP DESIGN PROTECTS CASING. The design of the slips and cones in Baker dual packers protects both casing and packer against excessive radial forces. (This also contributes to easy retrievability.)

IT IS READY TO RUN IN. When a Baker dual packer comes to the well, it's ready to run in. Slips, hold-down buttons, inside seals – they've all been tested and checked out at the factory. Their readiness is known.

SOMETHING TO KEEP IN MIND. Parts are always available, and so is service. Baker operates one of the great domestic oilfield service organizations.

SPECIAL FACTS ON PLANNING DUAL STRINGS
The variables of a dual-string hookup can be many. Baker field staffs are especially well prepared to discuss these things. They have all the latest facts and figures on Baker's intensive continuing study of dual completions. Please contact your Baker branch office for information.

BAKER
SNAP-SET DUAL PACKERS

BAKER OIL TOOLS, INC. | HOUSTON | LOS ANGELES | NEW YORK

"Of 48 gas producers completed as wildcats in the San Juan Basin last year, 42 were in the Dakota."

tral area of the San Juan Basin. Operators most definitely associated with development of the shallower gas reserves of the Basin also have done much of the deeper development.

Of the 1959 discoveries listed as Dakota producers, 12 were completed by El Paso Natural Gas or El Paso Natural Gas Products. Benson-Monti-Greer Drilling, Redfern & Herd, Skelly Oil, Continental Oil, Aztec Oil & Gas, Tennessee Gas, Pan American Petroleum, Southwest Production, Consolidated Oil & Gas, and Southern Union Gas are among the corporate operators with Dakota successes.

Individuals also drilled several Dakota pool openers, indicating that deals are available even though the majority of acreage is in the hands of the established San Juan Basin operators.

Oil and gas in Dakota. Surveys made during 1959 indicate that 10 to 15 percent of total drilling in the Basin during the year went to Dakota. Obviously, the percentage of exploration to this formation was higher, and this is the significant factor in appraising the San Juan Basin's present status as an exploratory province.

Gages on 1959 discoveries range from slightly below 1 million to upwards of 10 MMcf gas per day from Dakota. However, the gas producers from this formation do not tell the entire story.

Three oil discoveries were completed in the Dakota during 1959. Production ranged from 17 barrels per day to 202 barrels per day. The latter well was Continental Oil's Jicarilla-Apache 28-1, a flowing producer in the Otero area of Rio Arriba County.

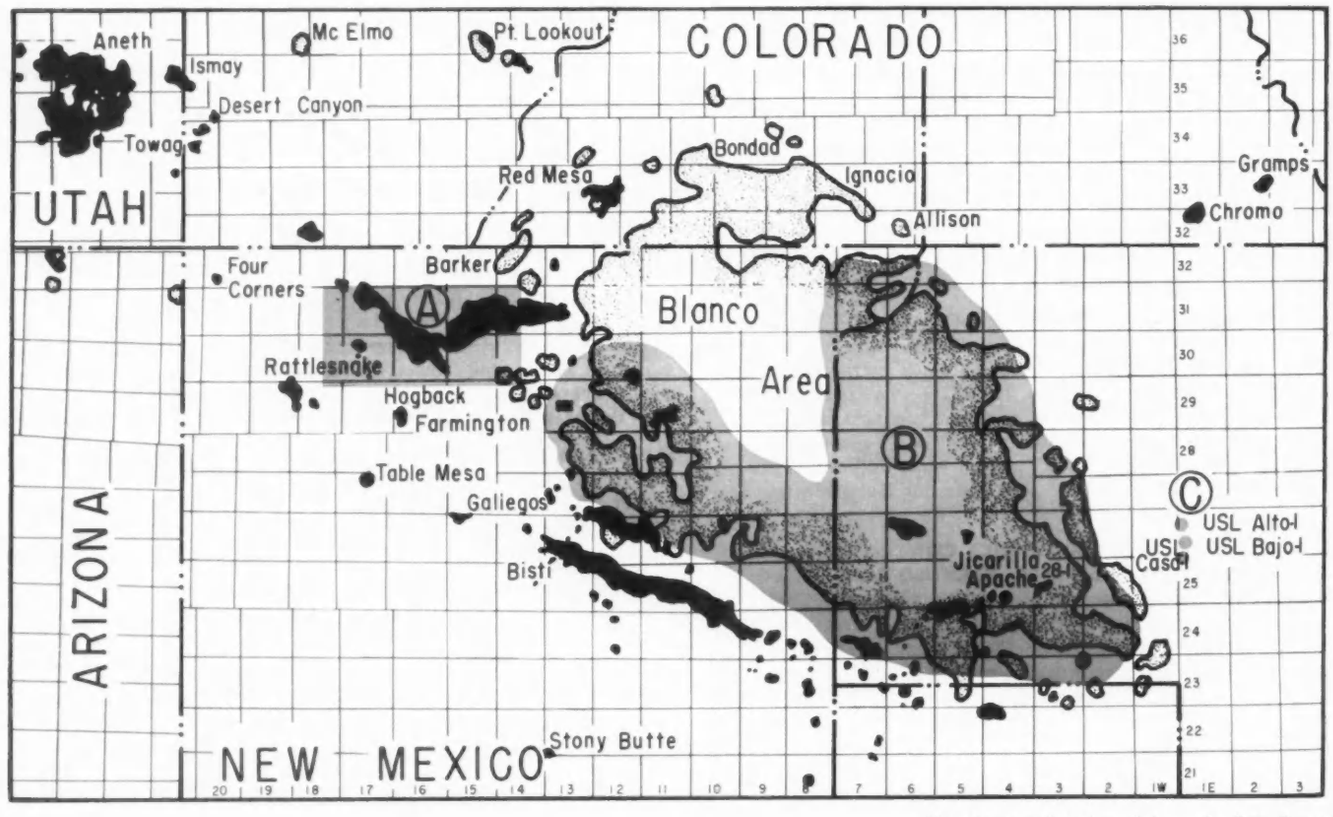
Oil production has been steadily extended through the southern portion of the Blanco area. Much of this is in trend with, but north of, the axis of the Bisti and Gallegos trends on the west side of the Blanco area.

Much of the oil production is from Gallup in the Upper Cretaceous. Consequently, drilling to Gallup which got its first impetus on the west side of Blanco has spread through the southern Blanco area. This in turn has affected exploration to Dakota, since if penetration is to be beyond Mesa Verde far enough to test Gallup, the extra risk in going to Dakota is relatively small.

Through the trend of successful Dakota exploration, wells are drilled to total depths of about 7,500-8,200 feet. As in other San Juan Basin areas, drilling is relatively rapid and comparatively cheap.

During the peak of activity in 1959

Major Exploration Areas in Northern New Mexico's Region of 'Surprise'



Map Courtesy Petroleum Information Inc., Denver

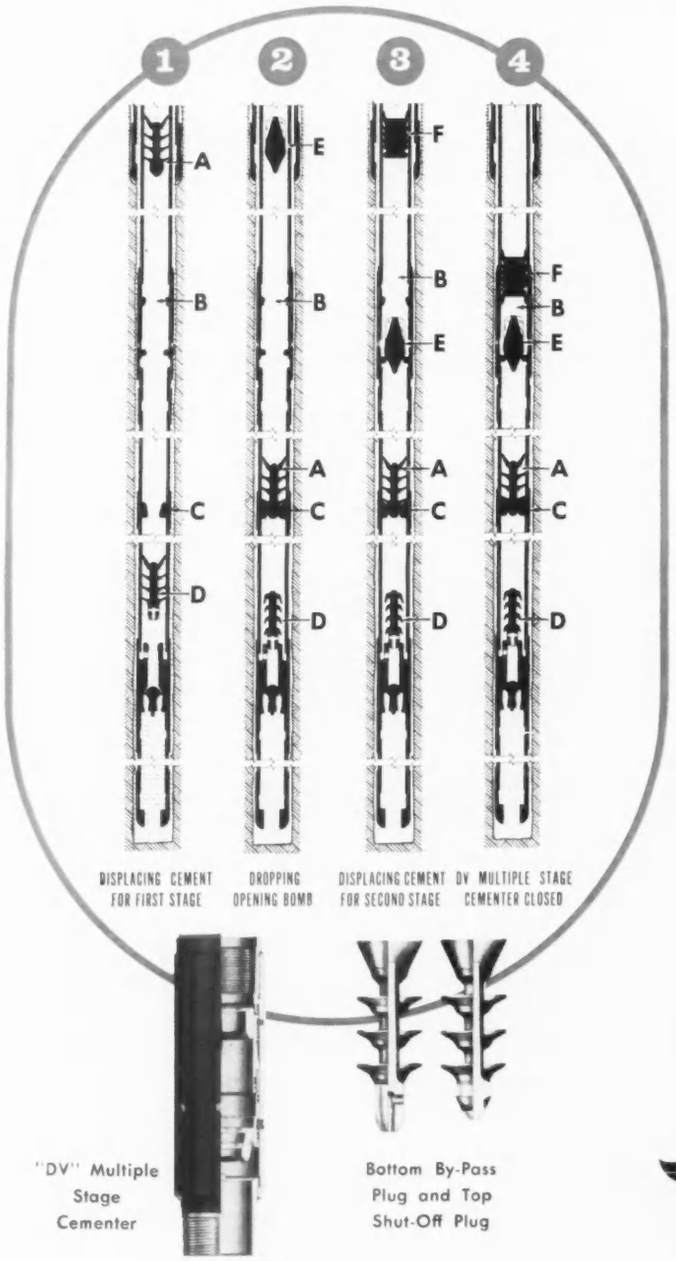
A—Chimney Rock-Horseshoe Canyon-Verde: Developed after the Bisti oil field, this area continues to be one of the basin's hottest oil provinces.

B—Dakota Play: Principal area of exploration to Dakota during 1959 and 1960.

C—Gallina Oil Field: Discovered early this year, has spurred new activity in this area.

4 STEPS TO SUCCESS

IN MULTI-STAGE CEMENTING



"DV" Multiple Stage Cementer

Bottom By-Pass Plug and Top Shut-Off Plug

If you've thought of multiple stage cementing only in connection with multi-zone completions, you may be missing many benefits that could be yours by using this system in conventional primary cementing. For instance,

DID YOU KNOW THAT MULTIPLE STAGE CEMENTING CAN HELP YOU . . .

- Get better *full depth* cementing?
- Reduce cement pumping pressures and possibility of channeling?
- Minimize cement slurry loss to thieving formations?
- Pinpoint cement placement at any depth?

The schematic drawings illustrate the *Steps to Success* in multiple stage cementing developed by Halliburton over the past 30 years.

1 STEP ONE . . . Bottom By-Pass Plug (D) leads the cement, displacing well fluid ahead of it, and seats in the By-Pass Baffle located on top of the Super Seal Float Collar after passing through the "DV" tool (ports closed). Openings in the Bottom Plug allow passage of cement through the plug. Shut-Off Plug (A) follows cement and seats in its Baffle (C) to complete the first stage job.

2 STEP TWO . . . Opening Bomb (E) is dropped through casing and seats in "DV" tool (B). Pressure is applied, opening the "DV" cementing ports.

3 STEP THREE . . . Second stage cement is pumped down, followed by Closing Plug (F).

4 STEP FOUR . . . Displacing fluid pumped behind Closing Plug (F) moves the cement through the open ports in the "DV" tool until Closing Plug (F) is seated in top of the tool which closes the ports and completes the job.

"DV" MULTIPLE STAGE CEMENTER . . .
is hydraulically operated by pump pressure to open after passage of first stage cement and close at completion of second stage.

BOTTOM BY-PASS AND TOP SHUT-OFF PLUGS . . .
for first (lower) stage of job. Note openings in bottom plug to allow passage of cement through Float Collar and Guide Shoe.

Ask your nearby Halliburton Representative to explain how this experience can pay off for you.

275 SERVICE CENTERS . . . JUST MINUTES AWAY FROM YOUR WELL

HALLIBURTON CEMENTING SERVICES

HALLIBURTON OIL WELL CEMENTING COMPANY • DUNCAN, OKLAHOMA

upwards of 60 rotaries were active in the area. Early this year activity dropped to about 20 rigs. This is because of severe weather and the difficulty in reaching locations in the Basin's rough country during winter weather.

With the coming of spring, the Basin is expected to open up with the rate of drilling expected to be higher than last year.

The amount and extent of both oil and gas production already found in Dakota insures additional development pressure.

Oil discoveries spark activity. Another boost to San Juan Basin prospects came early this year and as something of a surprise. Intex Oil, Bakersfield, California, drilled a shallow oil discovery 10 miles east and north of Gavilan gas field in Rio Arriba County. This well, USL-Alto 1, found production from fractured Niobrara shale. It pumped 130 barrels of oil per day from 1,929-58 feet. It was commenced as a test of Greenhorn, but was completed before penetrating that formation when the fractured shale zone appeared commercial.

This well was drilled with cable tools. Producers are relatively cheap, with $30,000 a good round estimate, even though the area is relatively remote. Since it is 75 miles from a pipe line, the oil which moves at wellhead for $2.65 per barel must support a considerable additional transportation cost.

Nevertheless, the Intex success offers the first recent prospect of a shallow oil pool tailored to an independent play since Horseshoe Canyon on the Basin's west side.

Intex staked several additional locations, and early in March had five either active or scheduled for early drilling. Two of these, while dry in the zone productive at the discovery, found shows of possibly commercial nature below that zone and were still heading for Greenhorn and/or Dakota.

In mid-March, Intex announced the results of two bailer tests of two hours each at Bajo 1. The well made oil at 14 barrels per hour on each of these two tests. Production is from 2,345-50 feet in First Sanastee. The well is 1½ miles southeast of the company's original discovery.

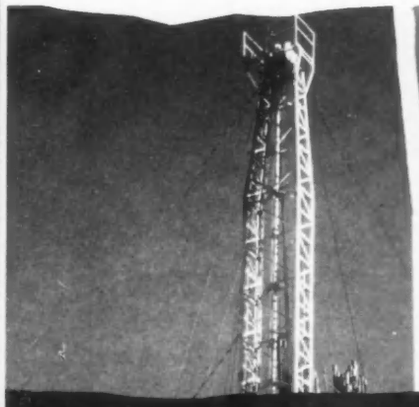
Shows of oil were first found in Bajo 1 at 2,015 feet, and these persisted through a considerable section. They were not of the caliber of those later tested in the Sanastee sand. During the bailer tests mentioned, fluid level was maintained at about 875 feet of bottom. First pump tests recovered 45 barrels of 34 gravity oil in 16 hours.

Sanastee is a sandy limestone which lies below the Gallup-Tocito section. It overlies the lower Mancos shale and the Greenhorn within the general Mancos (Cretaceous) series in this area.

Both the successful Intex wells were begun as Greenhorn tests. Both have stopped short of that objective, and both were stopped because they found oil.

The two wells are part of a six well series staked or active by Intex and its associates. A third well in the series, U & L Casa 1, had indicated possible production from Gallup by late March, but had not been conclusively tested.

The pool opened by Intex has been named Gallina field because of its proximity to the Gallina Mountains



Wilson

When more horsepower is needed . . . . . .

Easy enough, you say, on most rigs. But how about a self propelled rig? The *Wilson Winchmobile*, with cross-mounted engine, or engines, is the answer. Compounded, the engines both drive the winch drums and the rear axles. For really deep wells, this is the answer.

and the Gallina Mountain anticline.

Meanwhile, Kern County Land Company, on a series of farmouts from Petro-Atlas Corporation, became active in the area, and one of these was testing in late March. It is Petro-Federal 1, seven miles south of the Intex Bajo 1, and more than eight miles south of the first Intex discovery.

Oil play to increase. A sizeable demand for leases and farmout deals in this eastern San Juan Basin area arose after the Intex success. Again, the extent of development cannot be judged until the current drilling by Intex and Kern County Land is decisive.

Interest in oil development is becoming somewhat greater than for gas in the Basin. Expansion of refineries, connections available from both the Four Corners pipe line to the West Coast and the Texas-New Mexico line to the Gulf Coast provide markets.

This influence is reflected in the 1959 drilling record: During the year, 401 oil wells and 385 gas wells were completed in northern New Mexico.

Majority of this drilling was in the Chimney Rock-Horseshoe Canyon-Verde areas northwest of Farmington. These are shallow prospects where substantial production has come to be expected on the basis of work already done.

The new areas of oil production should command as rapid development as has been the case in the northwest Basin area.

Oil production in northern New Mexico last year totaled approximately 5.8 million barrels—up 72 percent over the previous year.

Geology is complex. Geologists credit the Gallina field oil production to Niobrara, Gallup or Tocito. These formations are roughly analogous. They also are roughly analogous to the productive formations at Bisti on the west side of Blanco.

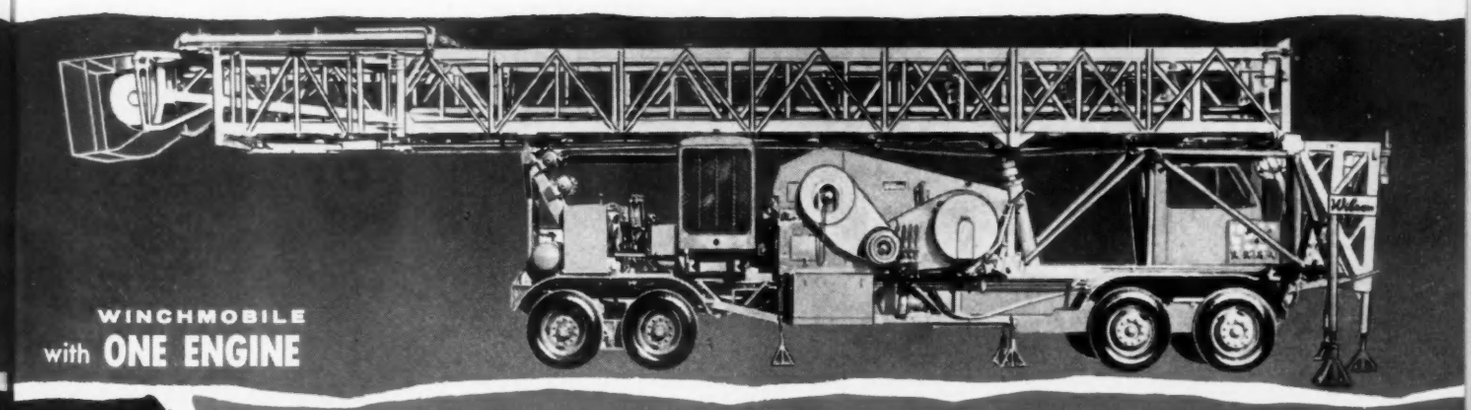
Recent activity has extended production from Gallup or equivalent eastward through the Blanco trend from Bisti and Horseshoe Canyon on the west to the Gallina area on the east. Several discoveries are centrally located between these east-west extremes.

The geology of the Basin is considered complex and a considerable amount of study is being given to the various stratigraphic conditions already known to exist.

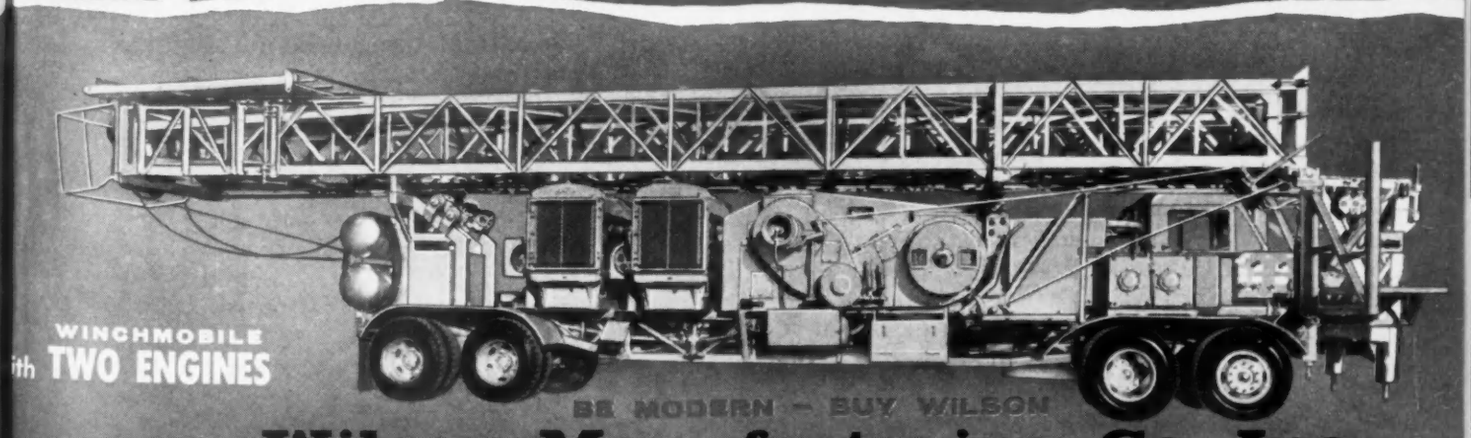
It is no surprise when geologists cite a new producing zone as "roughly equivalent . . .". The answers are just not all in. Until they are, the San Juan Basin will continue to produce surprises in this active exploratory province.

New drilling methods. The San Juan Basin has contributed a great deal to regional technology. Gas drilling made its entry to the region by way of the Basin. Sandfracturing techniques were introduced and perfected here, then spread through the remainder of the Rockies.

At the present time a considerable amount of experiment with the use of tubing as casing is being conducted in the Basin. Several operators have completed one or more wells using tubing, and expect that it will prove to be an effective means of reducing drilling costs in the Rocky Mountains. —**The End**

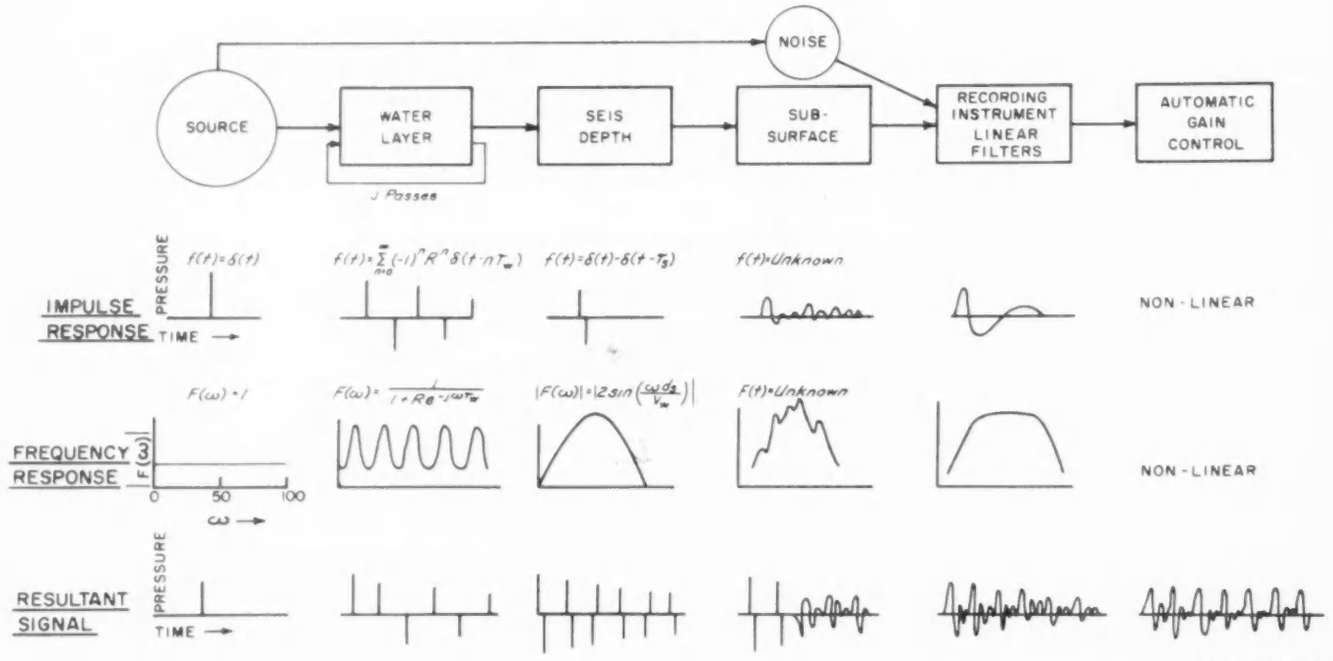


. . . . add another engine!



BE MODERN — BUY WILSON

Wilson Manufacturing Co., Inc.



After *Geophysics*

FIGURE 1—This diagram illustrates approximate filtering effects acting on marine seismic data. Detonation of explosives produces a disturbance which may be regarded as a positive pressure impulse on the seismic time scale. This impulse reverberates within the water layer, producing a series of impulses. Primary reflections essentially pass through two sections of the water-layer filter; section multiples may pass through a number of sections of the water-layer filter. The data pass through seismic instrument filters and conventionally are nonlinearly treated by automatic gain.

Inverse filtering helps solve problem of offshore multiples

New data-processing techniques erase water reverberations from marine seismograms

By Milo M. Backus
Chief Research Geophysicist
Geophysical Service Inc., Dallas

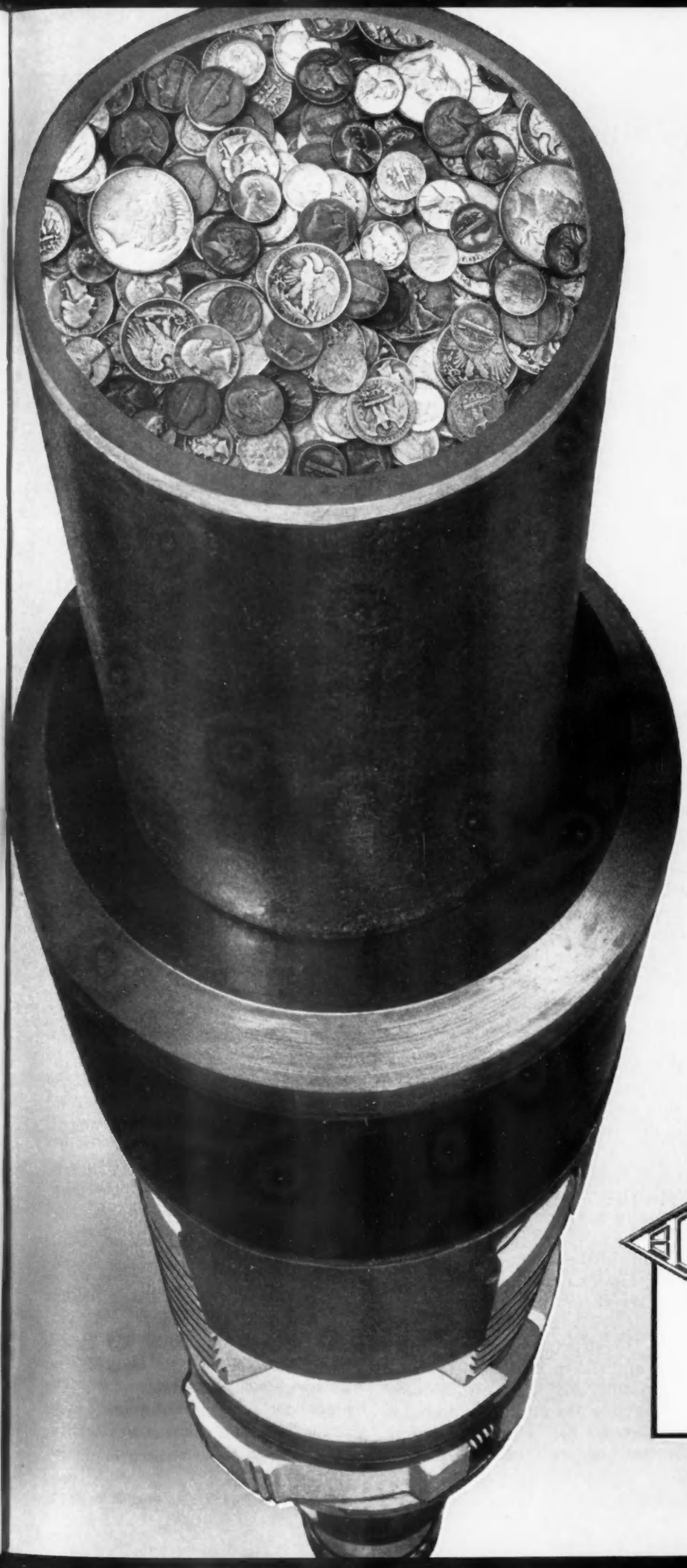
"MASKED REFLECTIONS" have long plagued marine seismic work in certain areas of the world. These reflections are valid ones from depth which are partially or almost totally obscured by the "singing" phenomenon which appears on some marine records owing to water reverberations. Analogous conditions occur in some onshore areas also.

Data-processing techniques have now been devised which in effect erase water reverberations and permit valid data to be presented in approximately the same form as it would have been obtained had the operation been shot on land.

The water reverberations problem was first reported in literature on the basis of the apparent periodicity of a suite of seismograms shot in the Persian Gulf. At the time, in 1951, it was treated by K. E. Burg and others for the one layer case by wave guide theory.

Water reverberations appear on marine seismograms in areas where the air-water interface and the water-bottom interface form an effective energy trap. In all marine work the air-water interface is a flat, strong reflector, with a reflection coefficient close to minus one. In the waters of the Persian Gulf and Lake Maracaibo, for example, the water-bottom interface is also a strong reflector. These two surfaces result in an energy trap bounded by two strong reflecting interfaces.

A pulse generated in the trap by a dynamite explosion in the case of seismic work will be successfully reflected between the two interfaces. The time interval between successive reverberations is equal to its two-way travel time and the amplitude decay



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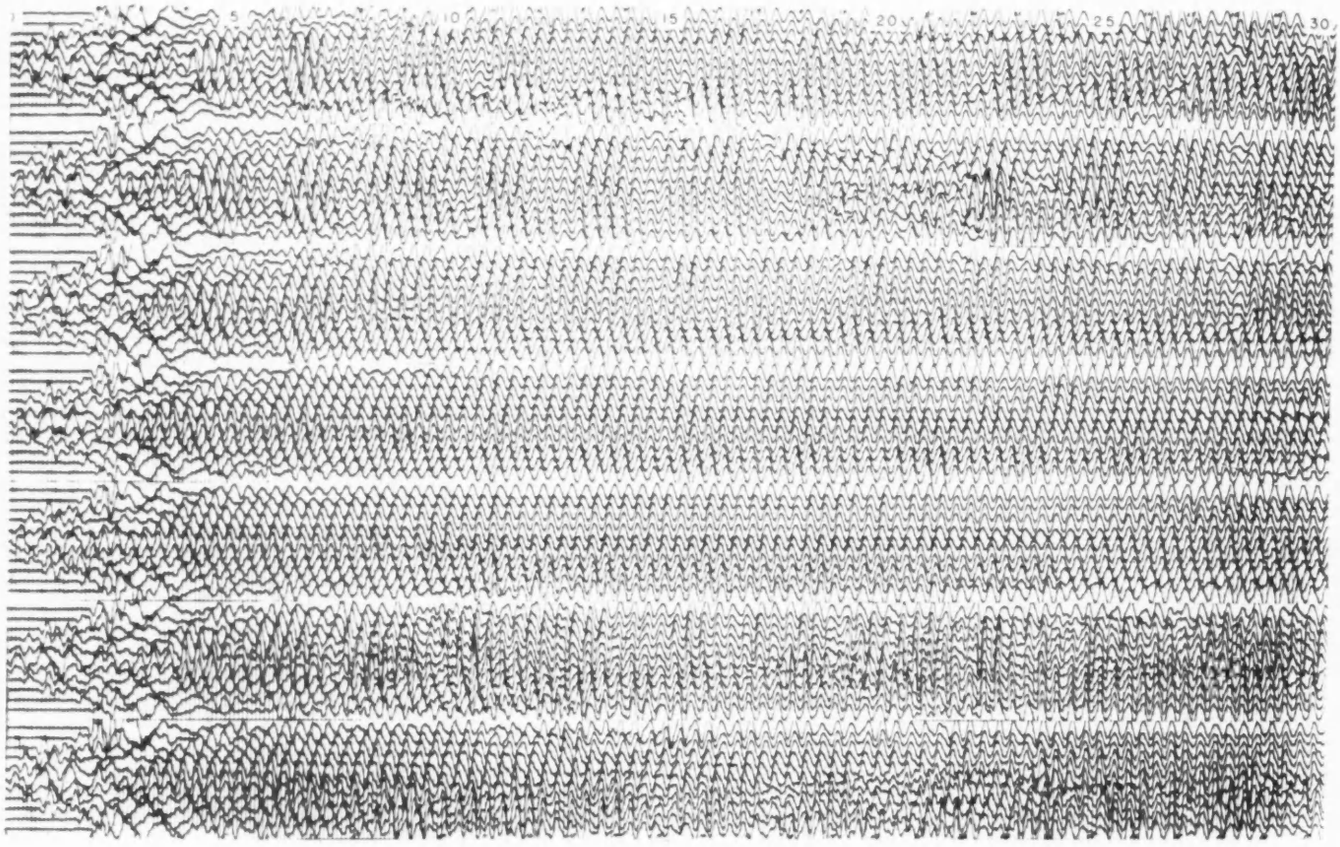


FIGURE 2—Suite of marine records, showing dominant water reverberations.

is dependent on its reflection coefficient. The resulting reverberations form the "singing" effect which masks valid reflections from depth.

Although the problem is most prevalent in the Persian Gulf and Lake Maracaibo regions it has also been encountered in the Gulf of Mexico and off the coast of California. Undoubtedly it is found to a certain extent in all marine areas where the conditions for its presence appear in varying degrees.

Recognizing the problem. The most striking feature in water reverberation areas is the apparent high quality of the records when they are examined individually. The large number of "line-ups" would gladden the heart of an inexperienced observer. However, when one tries to interpret a series of records in terms of continuous reflectors, the validity of the apparent single record line-ups is immediately in question.

The existence of the water reverberation problem is characterized by an apparent singing or dominant repetition interval on the records; by a sharply peaked frequency spectrum; by normal moveout intermediate between that expected for the true section velocity and that expected for the water velocity and by abnormally slow energy decay.

Effect of water reverberations on conventional structural interpretation. Records obtained in water reverberation areas are similar to those obtainable in a normal land prospect by using an extremely ringing filter. However, the resonant frequency and the degree of ring on the water reverberation records varies from profile to profile.

Water reverberation records differ from those shot on a normal prospect in that the ringing introduces invalid dip, *in accordance with the water bottom structure*. There is also a very significant build-up in energy associated with multiple reflectors between the surface and sub-surface reflectors.

Although the singing records *do* tend to mask valid information, most water reverberation records contain some recognizable data. In a case where (1) structures are large and simple and shown by shallow as well as deep dips; and (2) the subsurface is reasonably comformable and the water bottom flat, a conventional phantom interpretation of the records, considering the apparent line-ups to be valid, will serve to locate the structures.

Attempting to treat singing records with conventional interpretation techniques could, in the more general case, result in serious limitations and misconceptions of the true subsurface structure.

Very shallow picks could represent water-confined energy and the resultant picture would be simply an exaggerated representation of the ocean bottom.

Also, if conventional interpretation techniques are used, shallow structures tend to plot deep and are biased by the water bottom structure.

At any particular time the dominant energy will be connected with different subsurface reflectors as one moves laterally across a section. Thus the use of phantom horizons would give invalid results relative to any particular reflector.

Indications of deep structures on the singing records would, in general, represent water reverberations excited by shallow section multiples. Thus, the indicated deep structures would actually be shallow structures exag-

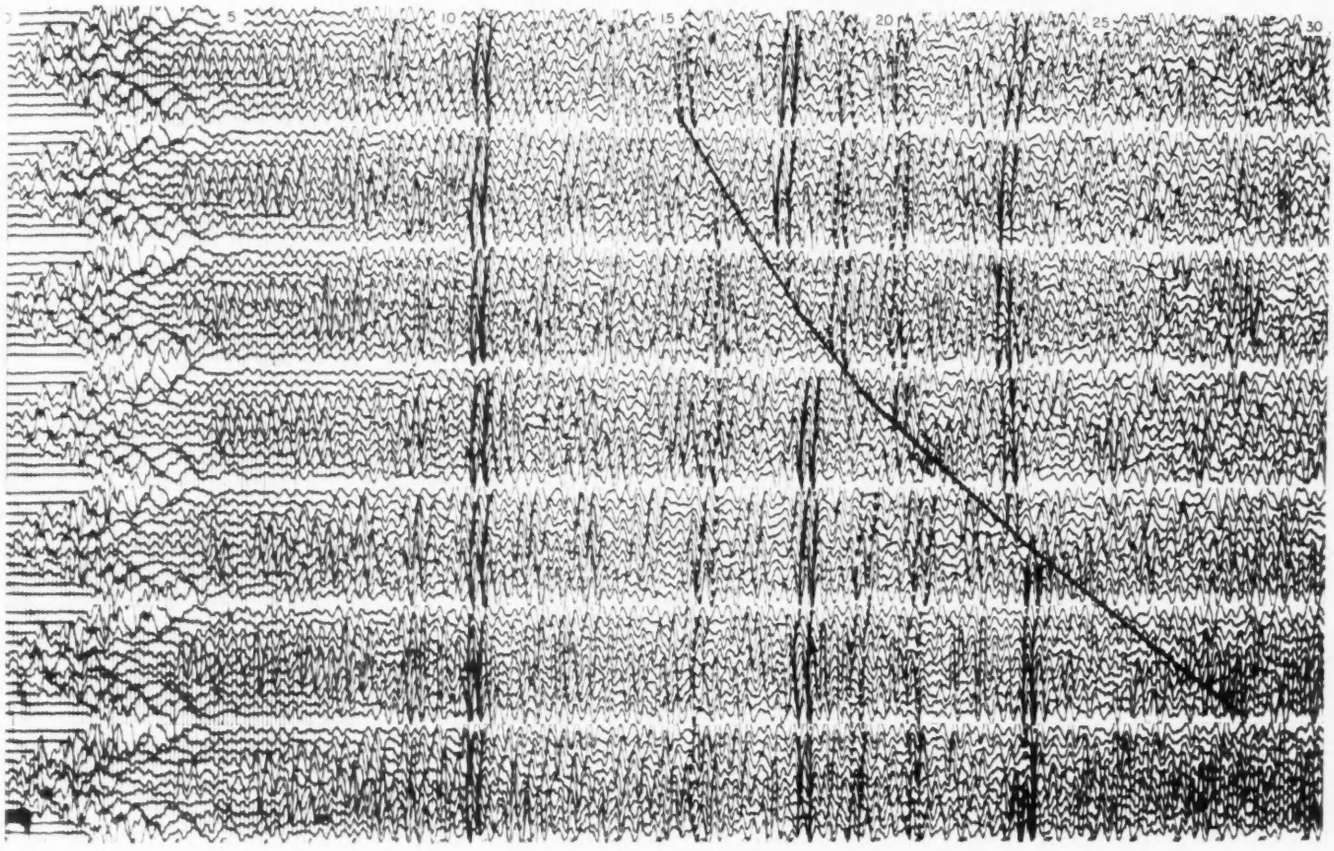


FIGURE 3—Suite of marine records (same as Figure 2) processed for removal of water reverberations.

gerated by the water-bottom structure; while the true deep uncomformable structures would be masked by the reverberations connected with the shallow reflectors.

Interpreting water reverberations in terms of linear filtering. Basically, if the reflection seismic method is regarded as an attempt to obtain approximately the impulse response of the subsurface to vertically traveling energy, then the amplitude peaks in the impulse response can be interpreted in terms of subsurface layering. Filtering of the impulse response within the seismic instruments, to gain a satisfactory signal-to-noise ratio, results in a degradation of the data as does ground filtering due to frequency dependent attenuation.

When a water layer is added to this we find that it can often be regarded as an additional undesirable and extremely sharp water-layer filter which further degrades the data.

Figure 1 illustrates the factors acting on data in marine work which may be considered to be the approximate filtering effects. The actual order of occurrence has been shifted for clarity in developing the final form of the seismic signal. The marine seismic source (typically 15 to 25 pounds of high velocity dynamite detonated 4 to 6 feet below the surface) produces a disturbance which may, on the seismic time scale, be regarded essentially as a positive pressure impulse. This pressure impulse reverberates within the water layer, producing a series of pulses. The resulting signal is further shaped by the position of the seismometer with respect to the water surface; however, this is treated as a separate filtering effect. The ringing signal is also transmitted into the subsurface and reflected back into the water layer. It is this portion of the filtering process which provides the desired subsurface data. Upon re-entry into the water layer, arrivals from the subsurface ring again.

Primary reflections thus essentially pass through two sections of the water-layer filter. Similarly, section multiples may pass through a number of sections of the water-layer filter. The data then pass through the seismic instrument filters and conventionally are nonlinearly treated by automatic gain.

Thus, in some marine areas the ringing or singing phenomena has almost completely masked valid data from depth.

Inverse filtering. There is little that can be done about the surface of the ocean, or the hard, flat bottom of the Persian Gulf and other difficult areas. However, if the action of the water layer is regarded as a linear filter acting on the data, the water layer is in effect removed, and about the same data obtainable from a dry floor may be acquired.

In considering the water layer as a linear filter the transfer function in frequency of the water layer may be shown to be:

$$K(f) = \left(\frac{1}{1 + Re^{-j2\pi f \tau_w}} \right)^2$$

where R is the water bottom reflection coefficient and τ_w is two-way travel time in the water layer. The resulting recorded data will be:

$$G(f) = F(f)\ K(f)$$

where $F(f)$ is the desired signal.

Therefore, if the recorded data is passed through a filter with a response

$$K(f) = \frac{1}{K(f)} = (1 + Re^{-j2\pi f \tau_w})^2$$

the desired reflection data, F(f) is recovered.

There is considerable difference between this concept and the usual seismic filtering concept.

In a conventional seismic work, a desired signal is recorded, plus noise. The characteristics of the signal and the noise are examined in terms of frequency and wave length. A filter is then used with a pass band limited to the frequency region where the signal-to-noise ratio is large, or a multiple-seismometer array is designed with a good signal-to-noise ratio in terms of wave length. Thus frequencies or wave lengths where the signal-to-noise ratio is low are filtered out and the resulting degradation is accepted in the desired signal.

An equivalent approach to singing records would be to regard the water reverberations as noise. A narrow band-pass filter fitted between two resonant peaks of the water-layer filter, or an arbitrary comb-notching filter to eliminate the reverberation frequencies, might then be used.

However, in the case of the water reverberation problem, this filtering approach often results in excessive degradation and sometimes complete elimination of the desired signal.

On the other hand, by using the concept of inverse filtering, primary reflection events can be recovered with the wave form which would have been obtained if the water layer had been removed.

Inverse filtering realization. In order to apply the principle of inverse filtering to singing records, it was necessary to design, build and utilize electronic equipment which could provide the proper transfer function in which the effective water-bottom reflection coefficient and the two-way travel time in the water layer could be conveniently set for each profile.

Since the reflection coefficient and two-way travel times differ from profile to profile, these must be accurately determined for each shot.

Recording techniques had to be modified to remove or minimize nonlinearities in the usual seismic recording system. The most serious of these is conventional automatic gain control.

Special recording techniques which maximize the true signal-to-noise ratio must be used in the marine work. Without these techniques, good-looking records of water reverberations may be obtained, but this does not necessarily imply that the original primary reflections from depth were recorded above the noise level.

Techniques of magnetic recording which permit maximum use of the dynamic range of the equipment must also be utilized.

In field recording, special high-fidelity marine seismometers are used. The data are recorded with modified seismic amplifiers in which the automatic gain control has been designed for an optimum compromise between maximum modulation on the magnetic medium and minimum change of amplitude relationships.

All data are magnetically recorded on discs and sent to a central office for processing.

The values of the water-bottom coefficient and the two-way travel time in the water layer are determined for each profile by analog computation on the data.

The inverse filter is conveniently synthesized with a time domain filter and the computed coefficients and travel times are set for each profile. The data can then be further processed by conventional means for presentation as corrected record sections.

Applications and limitations. Inverse filtering, when applied to problems of water reverberations, will provide seismic records which are approximately equivalent to those which would have been obtained in the absence of a water layer. However, these records become less valid as the ocean floor structure becomes increasingly complex or dips steeply. In areas where the water-bottom reflection coefficient is complex, the technique is limited.

The inverse filtering technique does provide considerable attenuation of section multiple energy; that is, those multiple reflections between the water surface and the subsurface reflectors.

Most important, marine records processed in this manner provide data from which valid structural interpretations can be made. These data are not obtainable in original water reverberation records, particularly when the subsurface is unconformable, or when traps other than simple broad anticlines are the target of exploration.

Although the technique of inverse filtering effectively reduces multiple reflections, it will not eliminate them. Inverse filtering alone will not produce usable records when strong noise problems other than multiples are present. Nor will it eliminate the need for exacting care in interpretation of records in water reverberation areas.

Other applications. The utilization of data processing based on simplified plane wave theory to solve a problem which had heretofore been practically insoluble indicates that inverse filtering through data processing may have definite application to other exploration problems.

The water reverberation effect is the most striking example to date of near surface phenomenon which can be regarded as a linear filter. However, other effects which vary from shot point to shot point, such as the shape of the outgoing pulse which cause variations in the character and apparent arrival time of events from profile to profile *but are unrelated to the subsurface*, can be attacked in the same manner.

ACKNOWLEDGMENT

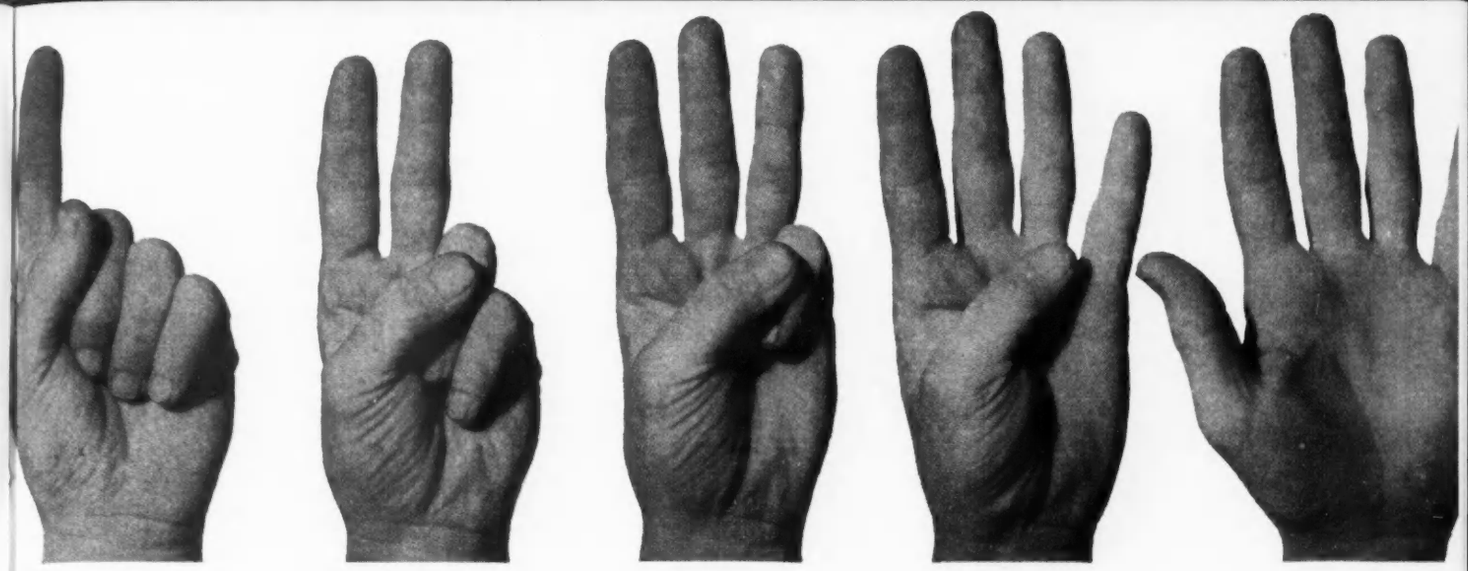
The previous paper[1] on this subject was intended to report research results. The article as published here covers problems and experience of operational usage.

LITERATURE CITED

[1] Backus, M. M., "Water Reverberations—Their Nature and Elimination," *Geophysics* 24, No. 2, 233-261 (1959).

About the Author

Dr. Milo M. Backus is chief research geophysicist for Geophysical Service Inc. (GSI), in Dallas, Texas. He obtained his bachelor's degree in geophysics in 1952 and his doctorate in 1956, both from Massachusetts Institute of Technology. After taking part in 1952 in GSI's summer training program, he joined GSI on a full-time basis in 1955 as a research seismologist. Dr. Backus is a member of the American Geophysical Union, the Society of Exploration Geophysicists, the European Association of Exploration Geophysicists, and Sigma Xi fraternity. He is the author of several technical papers on marine geology and geophysics.



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President Adolfo Lopez Mateos of Mexico actively promotes his country's vigorous industrial expansion. Besides controlling and encouraging the nationalized petroleum industry, the government actively encourages private development of the steel, copper, chemical, fertilizer, textile, paper and other industries.

Pascual Gutierrez Roldan is general manager of Petroleos Mexicanos, the government oil company. He is an engineer and financier with a successful background as a business executive. He came to Pemex more than a year ago after ably heading the Altos Hornos steel company at Monclova for about six years.

Mexico has active program of oil and gas development

By L. J. Logan
Associate Editor, WORLD OIL

PETROLEOS MEXICANOS, Mexico's government oil company, has under way in 1960 an active program of development and expansion. It plans to drill 506 development wells and 117 exploratory wells. It has been operating 96 drilling rigs, and will soon be using an additional 48 new drilling rigs. Pipe lines, refineries, and other facilities also are being expanded. Pemex is producing around 300,000 barrels per day of crude oil and natural gas liquids and considerable gas.

Nearly all of Mexico's oil and gas installations and several plants making steel products for the oil and gas industries were visited in March by a group of representatives of U.S. petroleum industry trade journals. This writer was among those on the tour, which was partially described in WORLD OIL of April 1960, page 122.

Installations visited on the tour included the following:

• **At Reynosa, Tamaulipas,** south of the U.S. border. Drilling wells, oil wells, gas wells, gas gathering systems, a topping plant to process 10,000 barrels per day of light crude oil, an absorption plant that processes 300 million cubic feet per day of natural gas from adjacent fields, and the Pemex district offices and housing center.

Dry gases are moved by pipe line to Monterrey and Saltillo, and will reach Torreon in May and Chihuahua later. Pemex also delivers 125 million cubic feet per day of dry natural gas to Texas Eastern Transmission Company for movement to the New York City area, under a long term contract. The price received for the exported gas will gradually increase. It is now about 15 cents per thousand cubic feet.

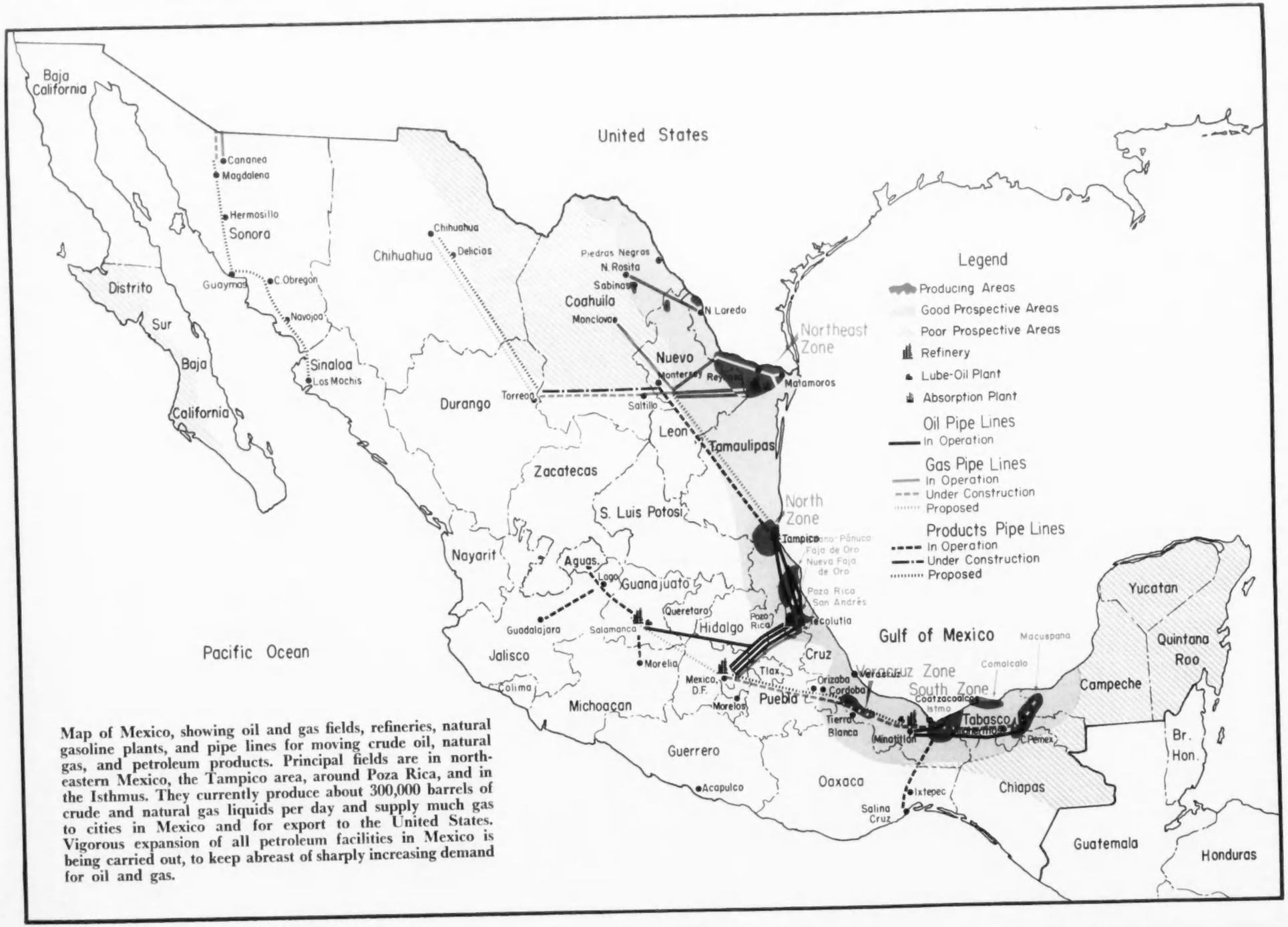
The absorption plant is being enlarged to 600 million cubic feet per day. The present installations produce daily 5,000 barrels of motor gasoline, 1,500 barrels of LPG, and smaller amounts of kerosine and residual fuels.

Near Reynosa is the huge 87 square mile Reynosa field, producing much gas and some oil from Frio (Oligocene) sands at depths around 5,750 feet. In the Reynosa district, below the Rio Grande River, there are now 32 gas and oil fields and 119 good prospects yet undrilled. The fields produce over 5,000 barrels of oil and 300 million cubic feet of gas per day.

In 1960 Pemex plans to drill 30 wildcats in this northeastern section of Mexico, between Monterrey and the coast. These fields so far are predominantly gas fields. They lie below Cameron, Hidalgo, and Starr Counties, Texas, which have numerous similar oil and gas fields, producing from related formations.

Northeastern Mexico has large oil and gas reserves already proved, and is confidently expected to yield ultimately oil measured in billions of barrels and natural gas in trillions of cubic feet. It is in an early stage of development, just as the Louisiana-Texas Gulf Coast was in the early 1930's.

• **At Ciudad Pemex, Tabasco,** in the Isthmus. Drilling wells, prolific gas wells, an absorption plant that recovers up to 3 gallons of liquids from 1,000 cubic feet of gas. The gas now is re-cycled, but later it will be sent



Map of Mexico, showing oil and gas fields, refineries, natural gasoline plants, and pipe lines for moving crude oil, natural gas, and petroleum products. Principal fields are in northeastern Mexico, the Tampico area, around Poza Rica, and in the Isthmus. They currently produce about 300,000 barrels of crude and natural gas liquids per day and supply much gas to cities in Mexico and for export to the United States. Vigorous expansion of all petroleum facilities in Mexico is being carried out, to keep abreast of sharply increasing demand for oil and gas.

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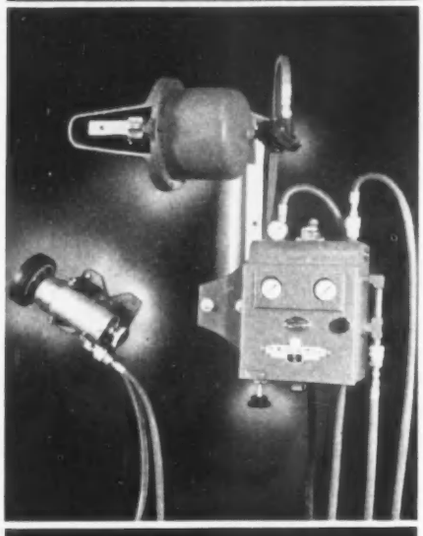

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into a pipe line for delivery to points northward, including Mexico City. The gas is produced in the adjacent José Colomo field, from several lower Miocene pay sands, including one that is as much as 1,000 feet thick. The wells are around 5,200 feet deep.

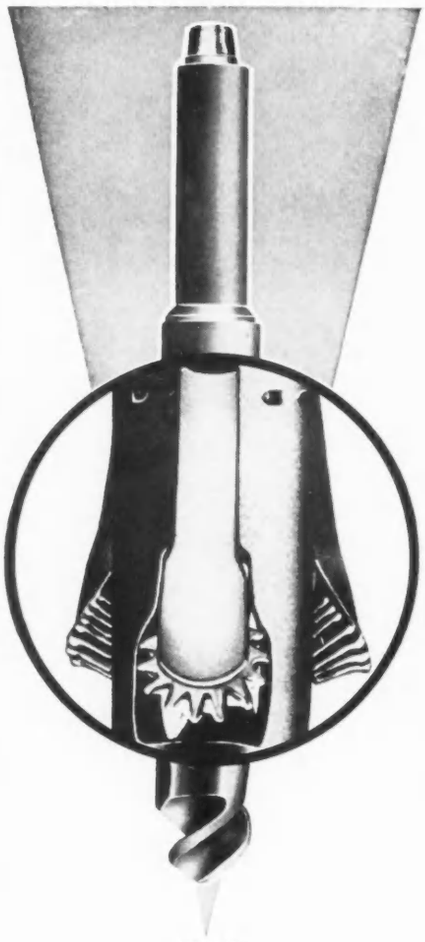
An individual gas well at José Colomo field is able to produce 30 million cubic feet per day and actually may produce over 7½ million daily of gas, from which 500 barrels a day of liquids are extracted. Such a well would yield $1,500 worth of liquids per day at $3 per barrel, or $550,000 worth per year; and the gas itself if sold at 20 cents per thousand cubic feet would be equally valuable.

In the field 36 gas wells are on production and 9 more are ready to produce, while there are 15 injection wells for re-cycling gas that has been treated. From the field about 260 to 275 million cubic feet of gas per day is piped to the absorption plant at Ciudad Pemex. From the gas 14,000 barrels per day of liquids are obtained. The liquids and light crude from the area are pumped in a 152 mile, 10 inch pipe line to Minatitlán refinery. The gas at present is being re-injected into the José Colomo reservoir.

The gasoline plant has a capacity of 300 million cubic feet per day. A gas pipe line is being built from Ciudad Pemex to Salamanca, 750 miles away. It will initially have a capacity of 300 million cubic feet daily and supply an expected immediate market of 140 million daily in 10 cities along the route, including the industrial Mexico City area. Plans call for future expansion of the capacity of the pipe line to 500 million feet daily and the plant capacity to 700 million daily, allowing for continued cycling of 200 million feet or more of gas per day.

The absorption plant is surrounded by a modern little city, Ciudad Pemex, built by Petroleos Mexicanos for its employees. The town was built where nothing existed three years ago, in the middle of a swamp in the center of the state of Tabasco, where rainfall measures 100 inches a year. The city has its own schools, church, theatre, and market, all being modern and neat.

To the west of Ciudad Pemex are the older salt dome oil fields of the Isthmus. The whole district is called the South Zone. In it 40 wildcats will be drilled in 1960. The area has 300 million barrels of proved oil reserves



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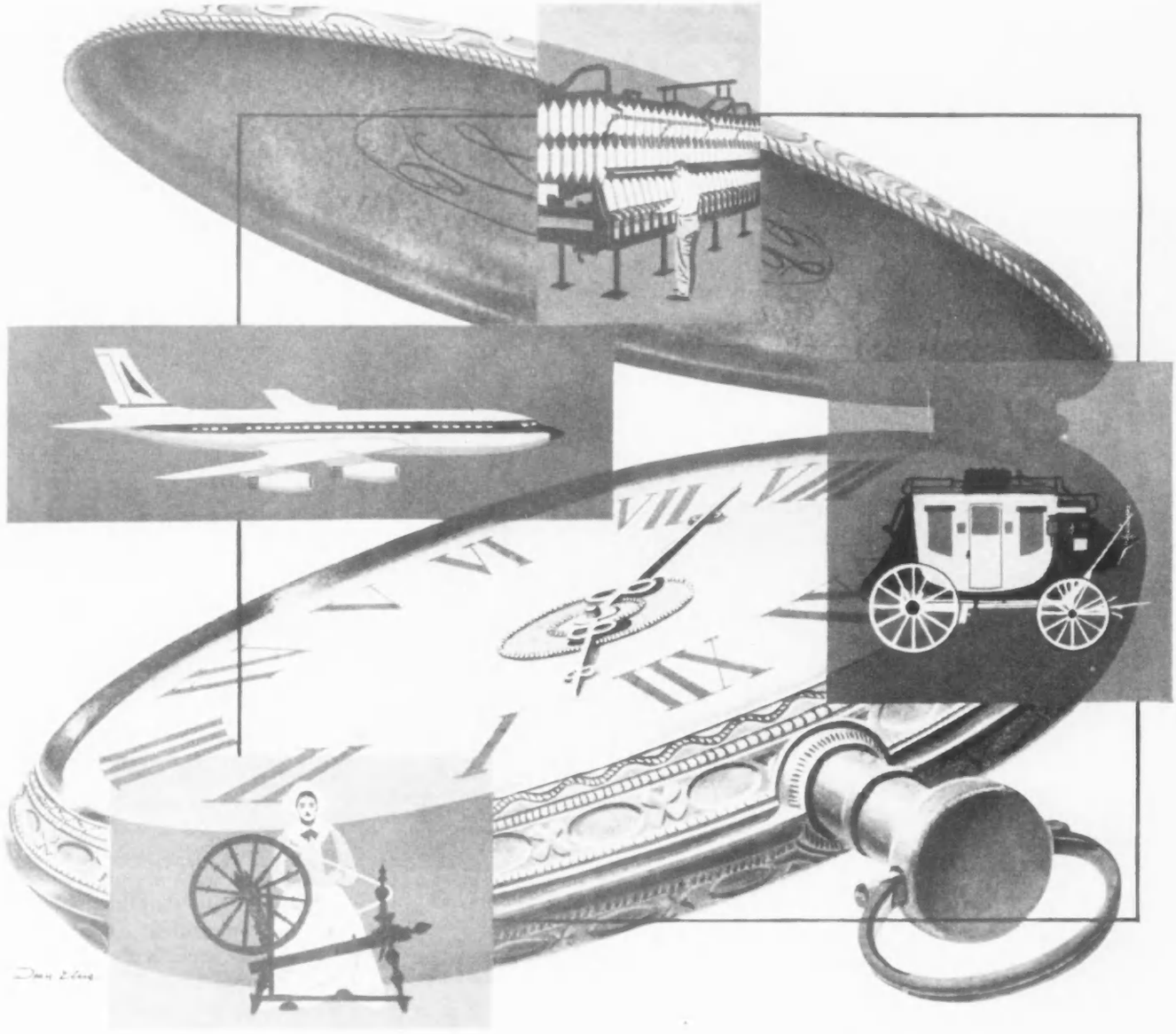

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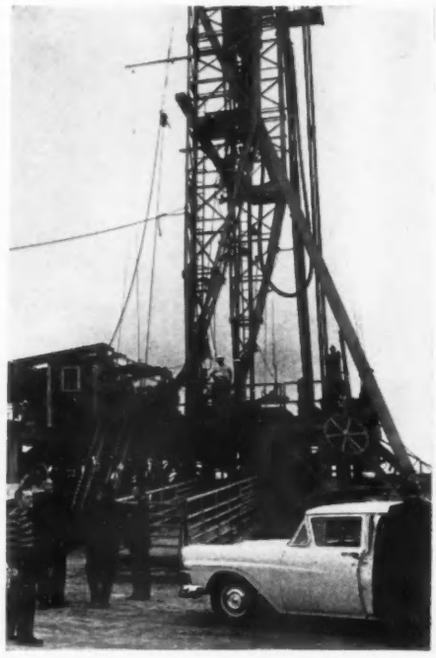
and at least one billion barrels of probable reserves. There are proved gas reserves of 2¼ trillion cubic feet at José Colomo field alone, and the South Zone may have 10 times that amount of gas reserves ultimately.

About 25 fields in the South Zone have combined crude production of 60,000 barrels daily from the lower Miocene sands at depths of 500 to 10,000 feet. In addition, José Colomo field produces about 14,000 barrels per day of natural gas liquids.

• **Vera Cruz.** This important port serves Mexico City. The TAMSA steel plant at Vera Cruz pierces ingots to make seamless pipe that is used as drill pipe, casing, and tubing in the oil and gas fields.

• **Poza Rica, Vera Cruz state.** Drilling wells, producing oil wells, an absorption plant. Poza Rica is still Mexico's most important oil field, largely supplying refineries at Mexico City and Tampico and at Salamanca to the northwest of the capital city.



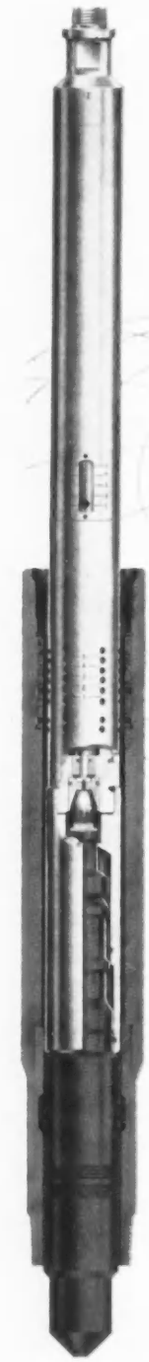
A typical mast type drilling rig owned and operated by Petroleos Mexicanos, and drilling in the Reynosa field of northeastern Mexico. Gas production in this field is obtained from prolific Frio (Oligocene) sands at depths of about 5,750 feet.

It is now producing about 75,000 barrels of oil daily, along with about 7,000 barrels daily of salt water from Cretaceous limestone at 7,000 feet. About 400 oil wells are producing, including about 100 that flow; and some more will be drilled, to extend the field on some sides and fill in undeveloped spots.

Poza Rica field has produced 762 million barrels of oil and has proved reserves of 1,219,000,000 barrels. About three fourths of the field's wells require artificial lifting equipment, and use gas lift, rod pumping, or hydraulic pumping.

Adjacent to Poza Rica field and believed to be a twin dome to Poza Rica on a regional high, is the new San Andres field, producing 29,000 barrels of oil daily from 85 flowing wells drilled into Jurassic limestone at 10,000 feet.

The Poza Rica district also includes some adjacent fields and wildcat areas. The whole district has production about double that of Poza Rica field. The district has produced 1 billion barrels of oil and has proved reserves of 1.77 billion barrels. It has produced 1.17 trillion cubic feet of gas and has gas reserves of 2.78 trillion feet. The district includes a southeasterly extension of the Golden Lane fields, where a series of structures has



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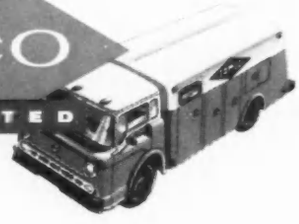

C 603

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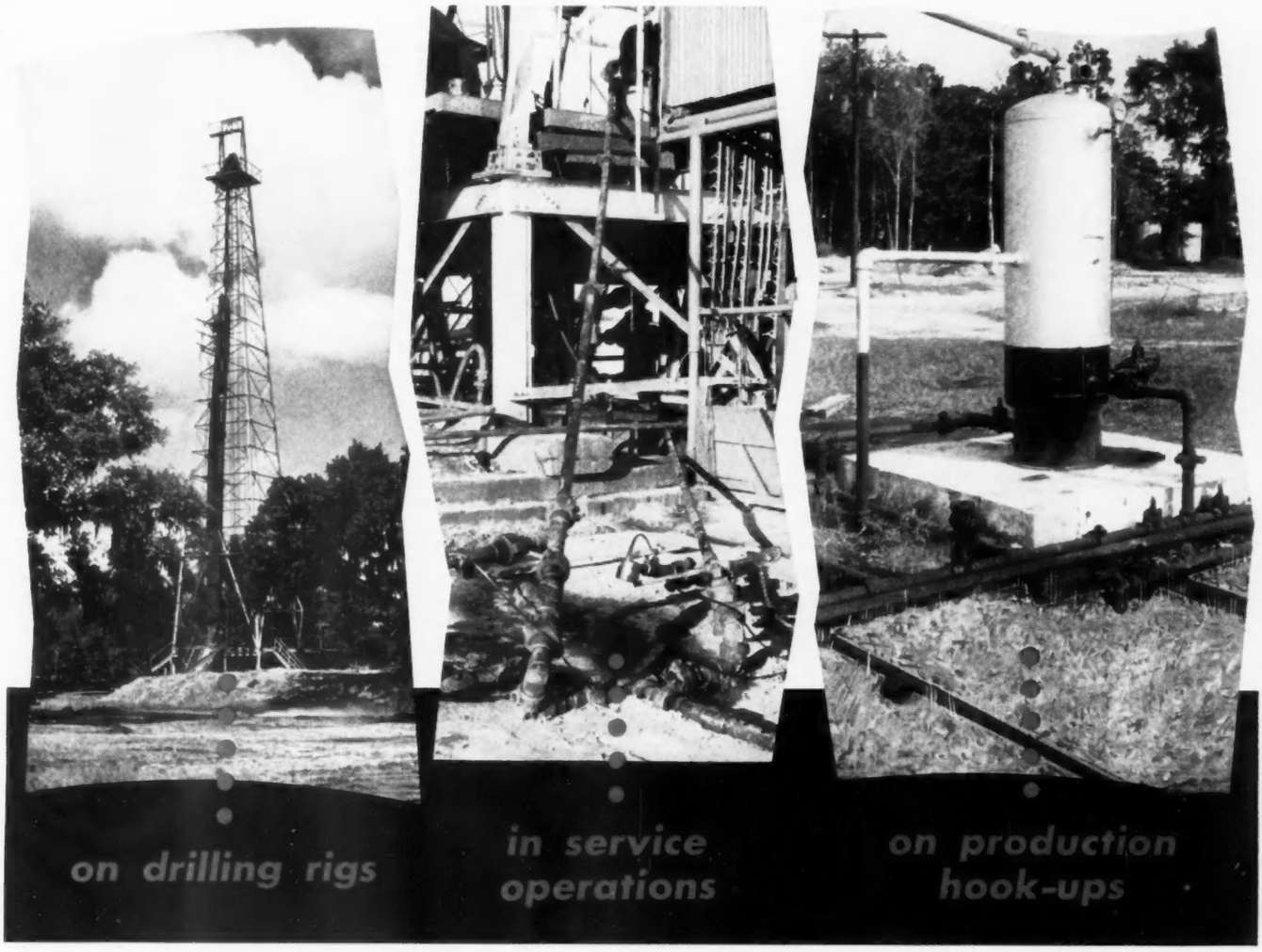
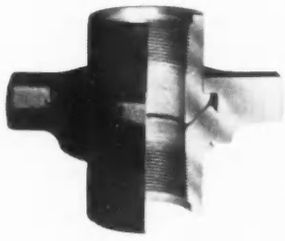


WECO UNIONS *mean greater service and economy*



Quality keynotes the design, engineering and manufacturing of WECO unions to give you better unions wherever they are needed in oil field operations. On the drilling rig, WECO unions mean faster rigging-up with greater assurance of dependable leak-proof piping. In service operations you rig-up fast and know that with WECO unions on the job you can handle the high pressures, high volumes and heavy abrasives of cementing, acidizing and sand fracturing without danger of leaks. When setting tanks, treaters, separators, installing field headers, manifolds and other production piping, WECO unions save time, and trouble.

There's hardly a place in the oil field where you won't benefit by standardizing with WECO unions. Sizes, pressure ratings and types for every service assure the right union for the service regardless of operating conditions.

Ask your WECO representative to help you plan a program of standardizing with WECO unions on your drilling rigs, your service trucks and equipment, your production installations. You'll save money in the long run.

U-3-60

WECO WELL EQUIPMENT MFG. CORP.
HOUSTON, TEXAS
Division of CHIKSAN COMPANY *a subsidiary of* FOOD MACHINERY AND CHEMICAL CORPORATION
fmc

WECO UNIONS

CHIKSAN SWIVEL JOINTS

HAMER LINE BLIND VALVES

HAMER PLUG VALVES

been found productive, yielding 20 gravity oil from depths of 3,350 to 7,600 feet.

There are now 24 oil and gas fields in the district. There are 37 drilling rigs at work in the district, including 26 Pemex rigs and 11 Mexican contractor rigs, with several more contractor rigs due to be employed. In addition there are 13 workover rigs in use.

There is no refining at Poza Rica. An absorption plant for 240 million cubic feet per day operates with gas from the oil well separators. A new topping plant is being built. It will process 15,000 barrels of oil daily, and is due for early completion. Electric energy is generated by Pemex for its own use and the town. Pemex plans to electrify all its installations. It operates a water treating plant, shops, and warehouses. Cementing of wells is done by contract with Mexican firms. Many services are performed by Pemex itself. About 9,000 people work for Pemex at Poza Rica, of which one half are permanent and one half perform temporary functions.

Exploration in the district is difficult. Knowing structures is not necessarily finding oil. Accumulations depend considerably on stratigraphic traps and character of the formations. Fields of the area have limited gas and water drives.

The city of Poza Rica, about 70,000 population, is primarily an oil center. It was only a village 15 years ago. Near it are some strange Indian ruins, where large hills have been cleared off to reveal huge temples in the shape of pyramids.

• **Tampico.** Refineries, drilling wells, famous oil fields. Heavy crude is produced by 100 percent effective water drive from the Cretaceous limestone fields of the Ebano-Panuco district and those of the Old Golden Lane and New Golden Lane. In the district there are now 27 wells drilling, including 10 exploratory and 17 development wells. Depths of 5,000 to 12,000 feet are reached. Last year 119 wells were drilled, and 220 more are scheduled for 1960.

The Ebano-Panuco fields now produce 15,000 barrels of oil per day, and Golden Lane fields 13,500 daily. Panuco fields already have produced 850 million barrels, and the Golden Lane 1,150 million, a total of 2 billion barrels for both areas. Remaining recoverable reserves are estimated at 500 to 700 million barrels.

At mid-March, 1960, Mexico's President Adolfo López Mateos, officials of Pemex, and other officials were due to dedicate the large new Ciudad Madera refinery at Tampico. It cost $45 million and will process 135,000 barrels of crude per day. It will replace four old refineries, of which three were still in operation in early 1960. Completion of this refinery provided a full set of modern, efficient, fully instrumented refineries in Mexico.

• **Mexico City.** The capital of the republic is the headquarters for Petroleos Mexicanos. Liaison with the federal government is therefore easy. The fuel needs of Mexico City and its surrounding area are supplied by the Atzcapotzalco refinery, located within the city. With a population of almost 5 million people and very heavy surface traffic, Mexico City is a large consumer of gasoline, using almost as much as Italy.

To supply these needs, the Atzcapotzalco refinery has been continually expanded during the past 15 years.

OILFIELD TRUCK AND FLOAT

Thornycroft Sandmaster 252" wheel base Oilfield Truck. Hands-England full Oilfield Body. 60,000 lb. winch, heavy duty gin poles, winch operated gin pole risers and folding SAE king pin.
Hands-England 75,000 lb. capacity, tandem axle Oilfield Float 30' 0" long and 9' 6" wide, folding support legs and inverted 36" fifth wheel.
Truck and Float on Michelin 18.00 x 25. Saharo "X" sand tires.

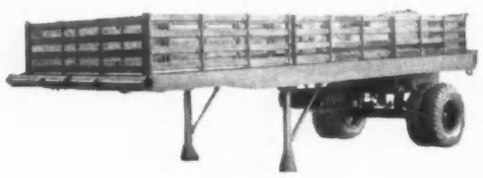
OILFIELD TRANSPORTATION EQUIPMENT

OILFIELD FLOAT

Hands-England 75,000 lb. capacity tandem axle Oilfield Float 30' 0" long and 8' 6" wide, folding support legs and inverted 36" fifth wheel.
Float on 11.00 x 20 — 14-ply tires.

OILFIELD TRUCK AND FLOAT

Scammel Constructor 261" wheel base Oilfield Truck.
Hands-England 75,000 lb. capacity tandem axle Oilfield Float 30' 0" long and 9' 6" wide, folding support legs and inverted 36" fifth wheel.
Truck and Float on 14.00 x 20 — 18-ply tires

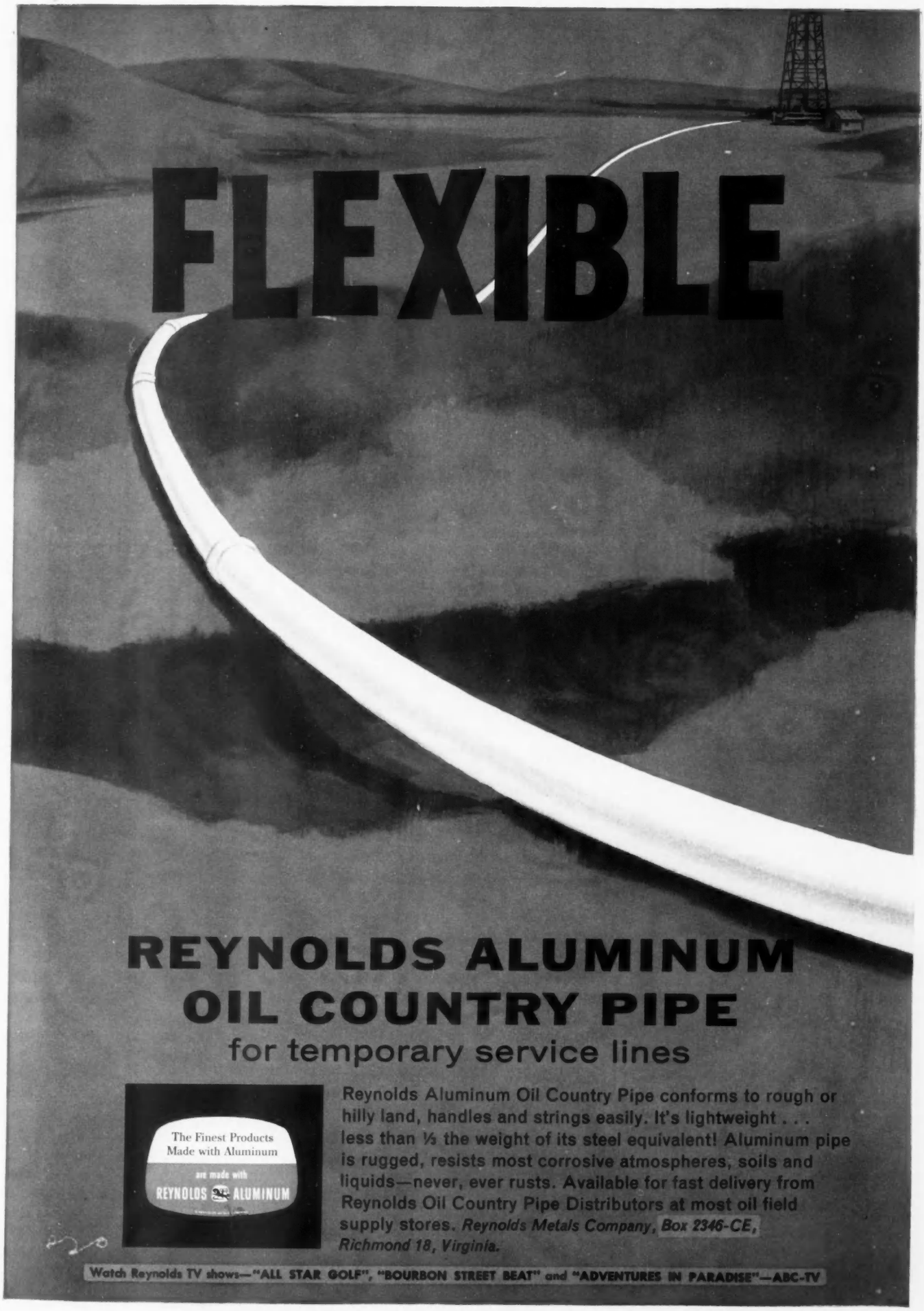


OILFIELD FLOAT

Hands-England 25,000 lb. capacity single axle Oilfield Float 24' 0" long and 8' 0" wide, folding support legs and SAE king pin 11.00 x 20—12-ply tires. Steel stake sides.

HANDS-ENGLAND OILFIELD EQUIPMENT LTD. Works Road, Letchworth, Herts., England.

Telephone: Letchworth 600 Telegrams: Oil, Letchworth. Cables: Oil, Letchworth, England.



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OIL COUNTRY PIPE
for temporary service lines

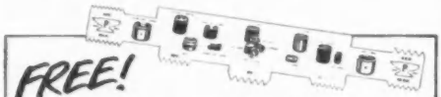
The Finest Products Made with Aluminum are made with REYNOLDS ALUMINUM

Reynolds Aluminum Oil Country Pipe conforms to rough or hilly land, handles and strings easily. It's lightweight . . . less than ⅓ the weight of its steel equivalent! Aluminum pipe is rugged, resists most corrosive atmospheres, soils and liquids—never, ever rusts. Available for fast delivery from Reynolds Oil Country Pipe Distributors at most oil field supply stores. *Reynolds Metals Company, Box 2346-CE, Richmond 18, Virginia.*

Watch Reynolds TV shows—"ALL STAR GOLF", "BOURBON STREET BEAT" and "ADVENTURES IN PARADISE"—ABC-TV

Anvil Brand Couplings start clean, run up fast because threads and chamfers are precision machined, gaged throughout manufacture, and electro-galvanized. Uniform wall thickness and properly aligned sealing surfaces provide dependable mechanical strength and full joints for trouble-free string service, minimum maintenance.

Anvil Brand Fittings—A.P.I. Couplings for all oil field applications, bushings, plugs, and nipples, are sold through your nearest supply store. Engineering service is always available from Anvil Brand Representatives in key oil country locations. Write for information.



FREE!

POCKET SIZE THREAD GAGE

Identifies threads from 8 to 14 per inch, round or sharp, external or internal. Only 6¼" long. Write Oil Field Dept., Pittsburgh Pipe and Coupling Co., Allison Park, Pa.

ANVIL BRAND
forged seamless and wrought steel pipe fittings

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PIPE and COUPLING COMPANY
ALLISON PARK, PA., U.S.A.

Subsidiary: Anvil Products, Inc., Longview, Tex.
Affiliate: Canadian Coupling and Fittings, Ltd., Simcoe, Ont.

Flow lines from 15 gas wells in the Reynosa field are brought into the common header shown here. Seven such gas gathering installations serve about 109 wells in the area. The gas yields gasoline and LPG in an absorption plant, and dry gas then moves by pipe line to Monterrey and other points in Mexico. Some is exported to the United States.

and has become a large, complete, and extremely modern installation. Today it refines 100,000 barrels per day of medium and heavy crudes, from Poza Rica and Golden Lane fields, and produces 30,000 barrels per day of gasolines, for automotive and aviation use.

Mexico plans to build up an important petrochemical industry, and has started the program at this refinery, where one plant recovers 25 tons a day of pure sulfur from refinery gases and another produces 45 tons a day of dodecylbenzene to supply the requirements of Mexico's private detergent industry.

• **Salamanca Refinery.** In the highlands northwest of Mexico City, this plant serves a populous area. It processes 40,000 barrels of crude per day, and is being enlarged to 80,000 daily by addition of a new topping unit. Six large units produce all high viscosity index lubricating oils used in the country. (Industrial lubricating oils are produced at the Minatitlán refinery in the Isthmus.)

The refinery is supplied with crude from the Poza Rica and Golden Lane areas by a 12 inch pipe line. Products leave the refinery through a network of products pipe lines toward three distribution depots in the cities of Aguascalientes, Guadalajara and Morelia.

Adjacent to the refinery a plant will be built soon to make 200 tons per day of ammonia. One private company will produce solids out of half the ammonia production, and another will produce carbon black from refinery materials.

• **Acapulco.** Pemex has a marine terminal and bulk plant here, for distributing gasoline, diesel oil, distillate fuel oil, and other products to the 70,000 population city of Acapulco and adjacent areas. This is the Riviera of the Western Hemisphere, a beautiful resort city on a large bay of the blue Pacific, where modern hotels regularly serve 25,000 or more tourists. Modern hotels and homes line the hills along the bay for miles. Gasoline and other oils come across the Isthmus by products pipe line and then by ship to Acapulco and other Pacific Coast points.

• **Monclova.** The Atlos Hornos steel plant at Monclova, Coahuila, northwest of Monterrey, takes coal, iron ore, and limestone out of adjacent mountains, makes ingots and pounds them into belts of sheet steel, from which are made many things, including tin cans and line pipe for oil, gas, water, etc.

From the sheets, another steel plant at Monterrey produces the pipe. There are also other steel plants in Mexico, and all but some special steel products are made in the country.

Adjacent to the steel plant at Monclava is a new plant that produces ammonia for making fertilizers. It is owned by private Mexican and French interests and consists largely of French equipment and instruments.

—**The End**

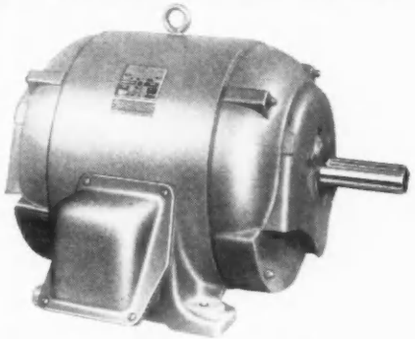
Your industry at work

A monthly roundup of items of interest about people, companies and associations

Sohio Research Center Addition Planned

Dr. E. C. Hughes (left), manager of the Research Department of The Standard Oil Company (Ohio), and Elliott B. McConnell, senior vice president in charge of research and manufacturing, at the dedication of one newly completed addition of the Sohio Research Center, discuss with other Sohio employes preliminary plans for the next addition to the center.

BROOK OIL WELL PUMPING MOTORS



COST LESS
TO BUY
TO OPERATE
TO MAINTAIN

This Brook a.c., polyphase, open drip proof, all-weather motor "breathes" to keep cool. Screened vent keeps out rodents. Has more of what it takes for long, dependable operation. Also Brook single phase oil well pumping motors and motors for refineries and petrochemical plants.
Send for brochure.

"World's Most Respected Motor"

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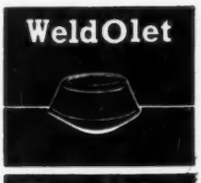
SINCE 1904
BROOK ELECTRIC MOTORS

BRANCH

CONNECTIONS

without cutting the run pipe

With Wilson Weldolet and associated fittings, full size and reducing size branch connections can be made, on site, if necessary, without cutting the run pipe. Self-aligning, shaped and bevelled, Weldolet fittings save time and material, maintain full pipe strength, and give uninterrupted flow.

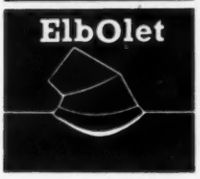


Weldolets for 90° branches, with weld to both run and branch pipes.

Sockolets as Weldolets, with sockets for branch to assist in lining up.

Thredolets produce threaded outlets, screwed connections.

Brazolets screwed or socketed outlet in bronze, for copper or brass piping.



Elbolets for elbow outlets and 45° branch connections screwed or socketed.

Sweepolets reinforced connections for butt welding.

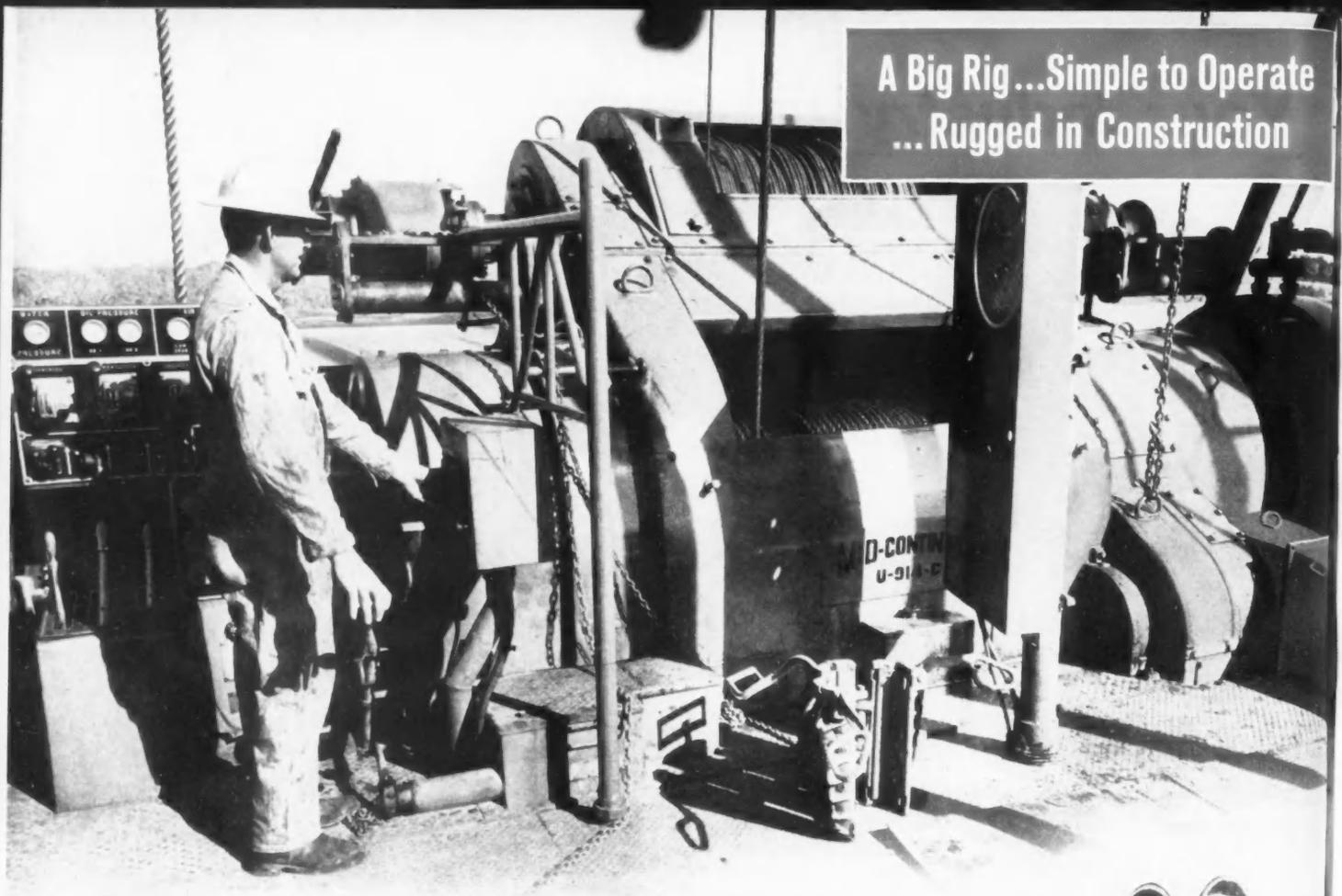
Please write for the 1960 Wilson-Weldolet Catalogue

WILSON

WILSON PIPE FITTINGS LTD.

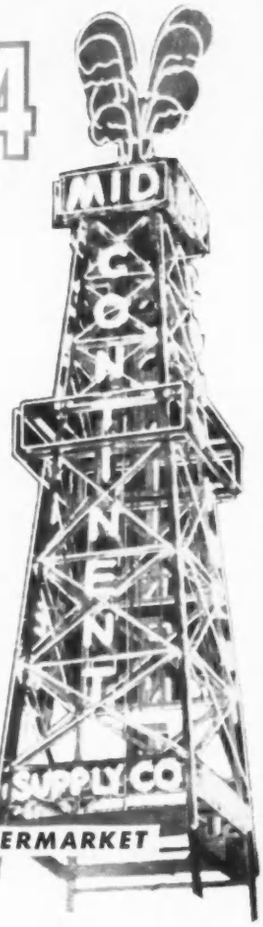
Irvine Ayrshire Scotland

London Office: 40 Palace Chambers, Bridge Street, S.W.1.



A Big Rig...Simple to Operate ...Rugged in Construction

MID-CONTINENT U-914



On location in South Texas, Stewart & Gouger Drilling Company's U-914 Drawworks is drilling "Deep Hole" for a major oil company. Rated at 900 to 1400 net input horsepower, this single package unit, single or double drum, is equipped with a 29" diameter by 53¼" long drum and self-equalizing, double adjustment brakes 10" wide by 52" outside diameter. Identical Fawick VC Clutches are mounted on the drum shaft for low and high drum drives, with an emergency splined clutch provided for the low drive. For dependable, economical and trouble-free drilling equipment, inland or offshore, call Mid-Continent today for complete information on the U-914.

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Your industry at work

H. P. Pressler Named to Oil Information Committee

Herman P. Pressler, Houston, vice president of the Humble Division, Humble Oil & Refining Company, has been named state vice chairman of the Oil Information Committee of Texas Mid-Continent Oil & Gas Association.

Pressler, who serves on the board of management of the present Humble Division, succeeds Eugene Hosford, Gulf Oil Corporation, Houston, who is the new OIC state chairman.

North Texas Association Elects Steed President

Netum A. Steed, Taubert and Steed Drilling Company, Wichita Falls, Texas, has been elected president of the North Texas Oil and Gas Association for the term of 1960-61. Other officers named include: David A. Kimbell, partner, Alan Drilling Company, Wichita Falls, first vice president; George W. Graham, independent operator, Wichita Falls, second vice president, and George W. Anderson, Wichita Falls, executive secretary.

Sunray Mid-Continent Oil Co. Reorganizes Records Section

Sunray Mid-Continent Oil Company has made its lease records section a part of the company's Exploration Department.

George B. Higgins, Jr., has been named supervisor of the lease records section, reporting to E. V. Potter, land manager for Sunray's Exploration Department, of which H. O. Harder is senior vice president.

The realignment is being made incident to the recent death of J. B. McDaniel, formerly manager of the Lease Records Department.

Geophysical Services Group Formed by Mobil Oil Co.

Mobil Oil Company has announced the formation of a Geophysical Services group at Dallas that will oversee Mobil's geophysical crews throughout the United States and assist in certain foreign geophysical operations.

The group's primary function will be to gather scientific data on the earth's subsurface—data used in the search for oil—for Mobil exploration offices coast-to-coast, including the major division offices at Houston, Midland, Texas, Denver and Los Angeles.

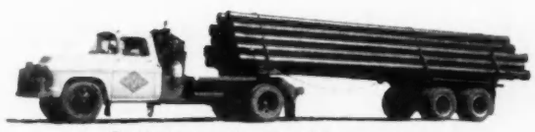
J. A. Lester has been named general manager of the new group. Other key appointments to the group include R. E. Horn, superintendent of geophysical field operations; M. D. McCarty, superintendent of engineering and maintenance, and A. W. Musgrave, superintendent of special problems. An additional superintendent will be appointed later to coordinate activities of the Geophysical Services group with Mobil geophysical operations in foreign countries.

Congrats and $25 to Robert W. GUTEKUNST, Esso Research and Engineering Company • Post Office Box 8, Linden, New Jersey

Joe Roughneck, backbone of the oil and gas industry, sees many a truck of tough Lone Star pipe roll onto well locations from the bayous of the Gulf Coast to the plains of the Williston basin. He knows delivery will be *on time* because Lone Star pipe is stockpiled . . . in quantity . . . in the heart of the oil country.

At Lone Star, every length of API casing, tubing, and line pipe is checked and tested through each manufacturing operation to insure strength and over-all uniformity . . . your guarantee of safe, dependable service on the job.

Neighbor, wherever you are, specify Lone Star and we both get a good deal.



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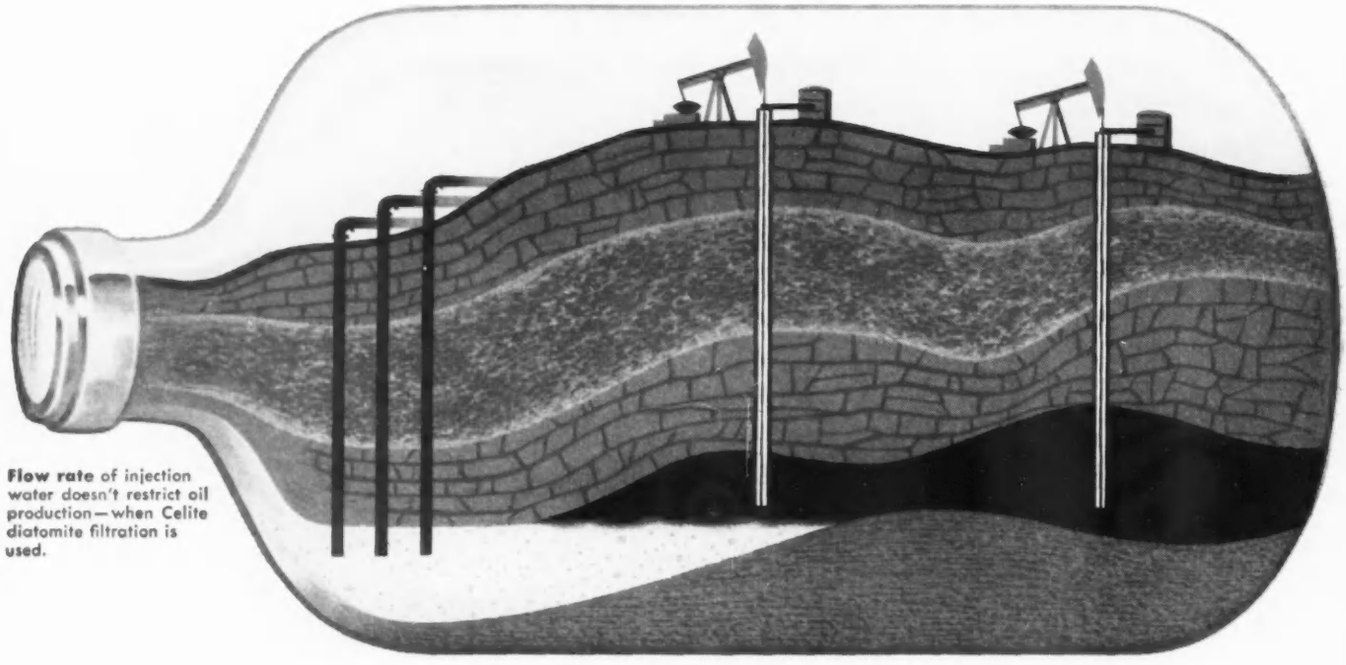


Flow rate of injection water doesn't restrict oil production—when Celite diatomite filtration is used.

No more *bottlenecks* in the formation pores!

Celite diatomite filtration removes all pore-clogging solids from injection water... permits fastest flow rates

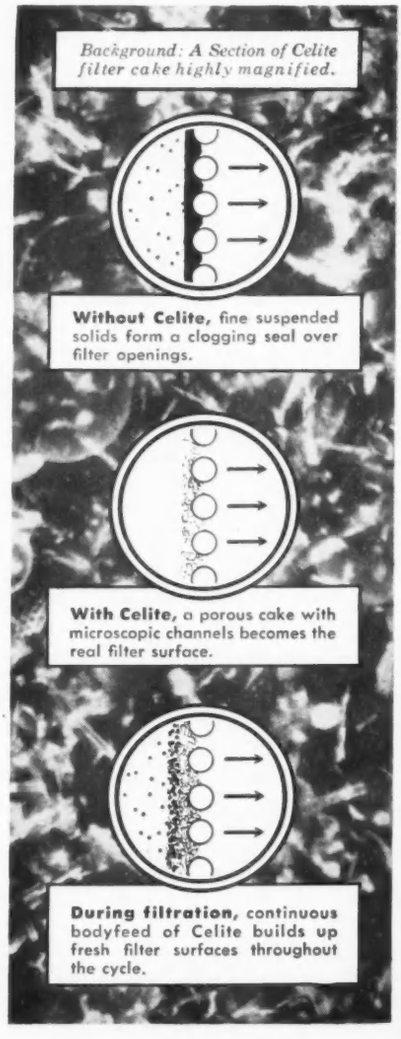
NOW YOU CAN PREVENT the build-up of suspended solids that sharply reduces injection water flow and oil output. J-M Celite filter aids take *all* clogging corrosive solids out of the water before they can get into the well.

Every cubic inch of Celite presents over 2.5 million microscopic filter channels for the water to pass through. These channels remove all corrosive products including oil, amoebae and most bacteria that plug injection wells. This results in sparkling clear water, maximum flow rate into the formation at lower pressures, and long uninterrupted periods of operation. A Celite filter unit requires 10 times less space than other types of filtration, is simply and easily cleaned and back on the line in a hurry.

Specially processed from the world's largest and purest commercially available deposit of diatomaceous silica, Celite is your best assurance of years of trouble-free filter operation. Nine standard grades have been developed to meet all filtration needs; you can pick the one that suits your system best. And when you reorder, you'll find that each grade of Celite remains constantly uniform.

A Celite engineer will be glad to help you set up a workable filtration system and recommend the proper grade of Celite powder for your needs. Write: Johns-Manville, Box 14, New York 16, N.Y. In Canada: Port Credit, Ontario.

*Celite is Johns-Manville's registered trade mark for its diatomaceous silica products.


Background: A Section of Celite filter cake highly magnified.
Without Celite, fine suspended solids form a clogging seal over filter openings.
With Celite, a porous cake with microscopic channels becomes the real filter surface.
During filtration, continuous bodyfeed of Celite builds up fresh filter surfaces throughout the cycle.

JOHNS-MANVILLE JM PRODUCTS

Your industry at work

Producing Properties, Inc. Buys Morrow Oil Interests

Producing Properties, Inc., has purchased from Morrow Oil Company of Los Angeles, the interest in certain properties previously acquired from the Southern California Petroleum Corporation, also of Los Angeles.

Under the terms of the sale, Morrow Oil Company retained an oil payment in the amount of approximately $1,351,000. Producing Properties paid $405,000 cash for the properties. The properties acquired consist of approximately 180 wells located on 59 leases which produce from 17 different fields located in California, New Mexico and Texas. The primary value of this purchase is in the Jalmat Area of Lea County, New Mexico, and in the Morales and Rosecrans-Athens fields, California.

It is estimated by PPI's engineers that this purchase will result in an increase in the net reserves of the Corporation of 519,251 barrels of oil and 11,039,222 Mcf of gas. These reserve estimates make complete allowance for the liquidation of the oil payment retained by Morrow Oil Company.

C. L. Suhr Paid Tribute By British American Oil

C. L. Suhr, Oil City, Pa., has been given special recognition for more than a half century of service as a director of The British American Oil Company Limited by that oil company. E. D. Loughney, B-A president of Toronto, Ont., presented Suhr with a sterling silver tray during the company's recent quarterly meeting of directors.

The tray is engraved with the signatures of all seven presidents the company has had to date, plus the signatures of all current directors.

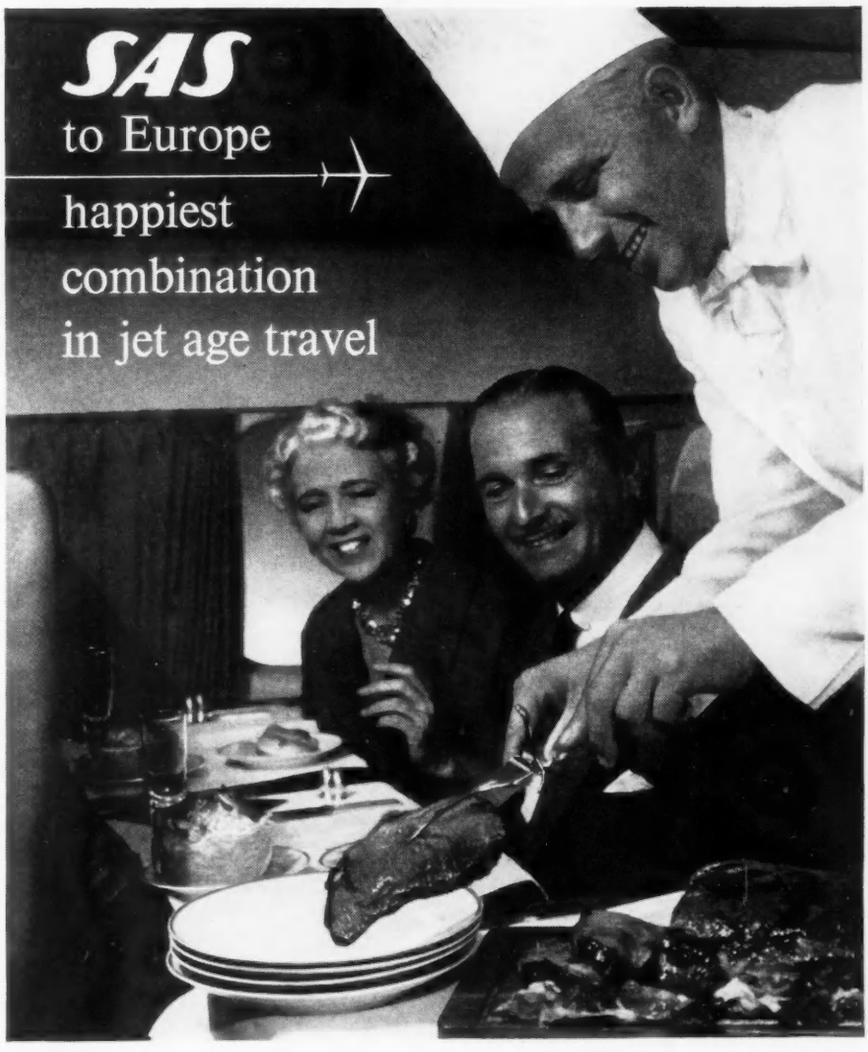
Suhr, who is chairman of the board of directors of the South Penn Oil Company, and a director of several other companies, joined B-A as a director in 1909, three years after its organization as a jobbing concern.

Kerr-McGee Oil Industries Establishes New Department

Kerr-McGee Oil Industries, Inc., has established a new department to coordinate the technical activities of the company and its subsidiaries in the fields of petroleum producing, refining and marketing.

The new department, known as Product Development and Quality Control, is located in Oklahoma City, and is under the supervision of Dr. D. R. Frey, general manager. Others assigned thus far to the department include L. W. Okon, manager of sales technical services; F. C. Champlin, chief chemist, and H. L. Norlin, laboratory supervisor.

The new department will act as liaison between marketing and manufacturing in the development of new products and changes in existing products.



for him on business,
for both on vacation

Starting this spring, you speed to Europe, transatlantic or transpolar, with magnificent hospitality on the *SAS* DC-8 Jet Express. Then you whisk through Europe and the Middle East on the *SAS* Caravelle, world's quietest pure jet. And for a gala vacation, you pick from 100 sun-and-fun holidays in the stunning *SAS* brochure, "Treasure Chest of World Travel". . . free. Ah, here is the happiest combination in the jet age! *At* your *SAS* agent.

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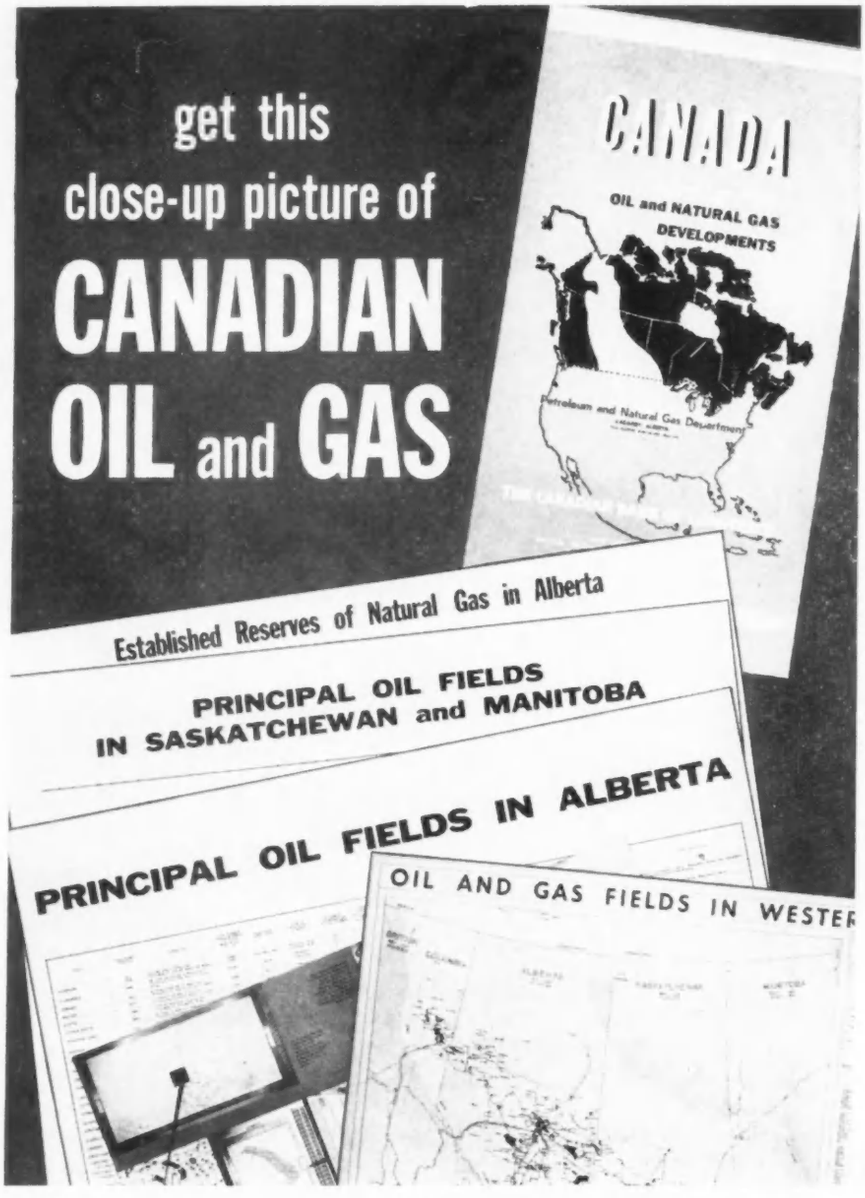

With a Petroleum and Natural Gas Department in Calgary staffed with technical men, and with nearly 300 of our branches located in Western Canada and the Northwest and Yukon Territories, we are in continuous touch with Canada's oil and gas developments. For information on any phase of the Canadian petroleum industry, please send your letterhead request for our complete and up-to-date review of developments. It contains our latest map, statistical data on the principal Canadian oil and gas fields, and a summary of the special services we offer to the industry.

Address your inquiry either to

Petroleum and Natural Gas Department
The Canadian Bank of Commerce
309 Eighth Avenue West
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Your industry at work

AAPG's 'Bulletin' Names Morrisey Advertising Manager

Norman S. Morrisey, formerly a consulting geologist in Tulsa, has been named advertising manager of *The Bulletin* of the American Association of petroleum Geologists, with headquarters in Tulsa.

N. S. Morrisey

Morrisey is a graduate of the Colorado School of Mines with a degree in geophysics and holds a M.S. degree in geological engineering from the University of Tulsa. From 1947 until 1954 he was employed by Pan American Petroleum Corporation; then Stanolind Oil and Gas Company, and later, was technical editor of the *Oil and Gas Journal*, Tulsa.

Dakota Petroleum Club Announces 1960 Officers

Steven H. Harris of Harris and Brown, was elected president of the Dakota Petroleum Club at the annual meeting held recently in Bismarck, N.D. The following officers also were elected for the ensuing year: Charles Skjod of Amerada, vice president; Leroy Blaylock, broker, secretary, and Tom Keating of Mobil Oil Company, treasurer.

The following men were named directors: R. W. Killen of California; Norman Lestins of Gulf Oil Corporation, and Woodrow Wilson of The Ohio Oil Company.

Ada Oil Opens New Wichita Falls Office

K. S. Adams and Ada Oil Company recently announced the opening of new district production offices in Wichita Falls, Texas, in the oil center. J. Merle Brewer will head the new office as district superintendent.

Brewer was formerly located in Abilene, Texas. Wichita Falls is more strategically located with reference to present areas of emphasis and this new office will replace the Abilene office being closed.

Tidewater Oil Honors Long-Service Employes

Tidewater Oil Company's long-service employes from Maine to North Carolina journeyed to New York City recently for the company's Thirteenth Annual Diamond Service Emblem Dinner.

A total of 153 men and women, whose individual service ranges from 25 to 40 years and whose aggregate service totals more than 46 centuries, were presented diamond-studded gold service pins bearing the company's Flying A insignia. J. G. Jimenez, vice president and Tidewater's eastern division general manager, presented the awards.

For more data on advertised products, use Readers' Service Cards, last page.

Men in the industry

J. R. White

E. G. Collado

E. G. Collado, treasurer of **Standard Oil Company (New Jersey),** and **J. R. White,** president of **Imperial Oil Limited of Canada,** an affiliated company of Standard Oil, have been designated candidates for election to the board of directors at Jersey Standard's annual meeting May 25.

Kenneth R. Joynt of Houston has been elected a director of **Mobil Oil of Canada, Ltd.** He was also named vice president and manager of production for the Calgary, Alta., affiliate of **Mobil Oil Company.**

Robert L. Wood has been elected assistant secretary-treasurer of **Southwest Gas Producing Company, Inc. Fred K. Golson, Jr.,** will succeed Wood as chief clerk in the Accounting Department. **Al E. Beasley** has been promoted to general exploration manager and will be located in Monroe, La. **Fred H. Plitt** has been promoted to senior petroleum engineer in the Production Department, headed by **R. F. Cox,** general production superintendent.

C. F. (Chet) Whaley has become vice president of **Columbia Drilling Company,** Houston. The appointment was effective May 1. Whaley formerly was president of Chet Whaley Well Servicing Company, Inc., Houston. Whaley and **J. U. Teague,** president of Columbia Drilling, are directors and past presidents of the American Association of Oilwell Drilling Contractors.

C. F. Whaley

Stewart Cronin, exploration manager, **The Pure Oil Company,** will transfer to Calgary, Alta., around June 1, to take charge of Pure's activities in Canada and Alaska. **Karl A. Mygal,** geological representative in Calgary, will transfer to the company's new Northern Producing Division headquarters in Denver. **Joseph P. LaCroix** will become manager of services, supervising divisional accounting budgets, personnel and material matters. **Fred A. Devin** of the Rocky Mountain Producing Division will transfer to Chicago as exploration manager. Assisting him will be **John H. Maher** as chief stratigrapher and **JLee Davis** as chief geophysicist. **Chester M. Harden** will become manager of production with headquarters in Chicago. **James R. McChesney** will remain as manager of the Gas Department and **Floyd L. Stewart** as chief production engineer. **Raymond H. Rantala** of the geological staff will become manager of exploration with responsibility for evaluation studies of production and reserves.

B. L. Francis has been appointed staff petroleum engineer of the Domestic Producing Department of **Texaco Inc.** in New York.

A. F. Woodward

A. F. Woodward has been appointed manager of field and exploration operations, Pacific Coast Division, for **Union Oil Company.** At the same time, **C. F. Bowden,** chief engineer, Pacific Coast Division, was appointed assistant to the vice president in charge of production.

John Sosnowski and **Edward J. Wickson** have been named research associates, and **Franklin W. Church** and **Russell R. Johnson** have been named engineering associates with **Esso Research and Engineering Company.**

Albert Benjamin has been named director of public relations for **Texaco Inc.** He succeeds **Thomas D. Durrance** who was appointed manager of public relations for Texaco's affiliate, **Arabian American Oil Company.**

Robert S. Burke has been appointed manager of the Land Department for **Associated Oil & Gas Company.**

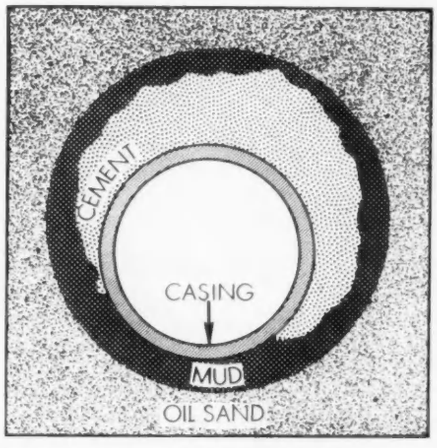
J. W. Meehan has been elected to the board of directors and named vice president of **The Vickers Petroleum Company, Inc.** He was formerly president of **The Derby Refining Company** of Wichita, Kans., division of **Colorado Gas and Oil Company.** Meehan also has been named president of **The Vickers Refining Company,** a newly created separate division of the company.

Dr. H. Dayton Wilde has been named to the newly created position of university relations counselor for **Humble Oil & Refining Company.** He has been serving as research coordinator.

B and W Inc.
SCRATCHERS AND CENTRALIZERS
for a good cement job

CHANNELING
is defined as . . .

CHAN'NEL.ING 1. To form a channel in; to groove. 2. To convey into or through a channel or channels. 3. Oil Well Drilling. In well cementing, a condition resulting from incomplete removal of fluid, gelled mud and filter cake from behind the casing by the ascending cement slurry.



CHANNELING MEANS . . .

(1) An imperfect primary cement job
(2) Mud left behind the casing
(3) Expensive squeezing
(4) A poor completion

B and W
SCRATCHERS AND CENTRALIZERS

Your best and most economical insurance for the elimination of channeling and a good primary cement job.

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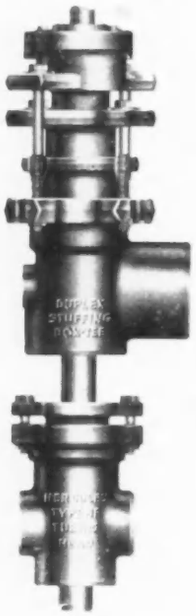
For more data on advertised products, use Readers' Service Cards, last page.

slim hole EQUIPMENT

FIRST from HERCULES

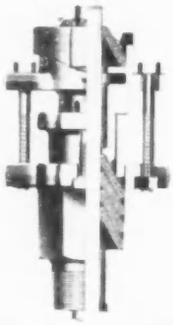
HERCULES is First to provide a complete line of equipment for this new Oil Production Technique.

The use of 2½" tubing for casing and 1¼" or 1½" tubing as the oil string has made it necessary to develop new equipment specifically for this purpose. In response to the requests of production men, Hercules now provides tested and proven production equipment for Slim Hole Drilling. The well-known Hercules "Tee-Type" Duplex Stuffing Box and the new 2½" Hercules Type "HF" Tubing Head are incorporated in this typical Slim Hole well hook-up. Hercules "Tee-Type" Duplex Stuffing Box is now available in 1¼" and 1½" tubing sizes (plain or EUE) with the same packing and parts used in all Hercules Duplex Stuffing Boxes.



HERCULES "TEE TYPE" DUPLEX STUFFING BOX A combination Tee and Stuffing Box with female thread to screw directly onto the 1¼" or 1½" tubing, eliminating one-threaded connection and resulting in a considerably shorter hook-up. 3000 PSI test. Approximate height 15". Weight 33#. Price $31.00.

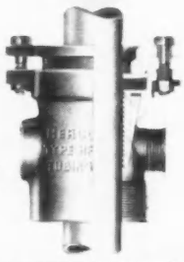
HERCULES TYPE "HF" SLIM HOLE TUBING HEAD Features the safety and quality that you receive in all Hercules tubing heads at a minimum price. Pressure cast, one piece steel body with 2" side outlets and heat-treated hinged slips. Over-head packed with neoprene packing. 1000 PSI test. Height 8½". Weight 19#. Price $49.50.



HERCULES "REGULAR TYPE" DUPLEX STUFFING BOX Proven design and dependability render this stuffing box unequalled for the difficult pumping situations as well as easy ones. Constructed from malleable iron, it protects workers from the danger of shattered metals should rods accidentally drop. The new 1¼" or 1½" "Regular Type" Stuffing Box is ideal for use in Slim Hole installations.

HERCULES TYPE "DS" PUMPING TEES In the 1¼" and 1½" sizes these Tees are ideal for use on Slim Hole well hook-ups.

HERCULES TYPE "HF" TUBING HEAD In spite of its economical price, the Type "HF" Tubing Head is pressure cast with one piece cast body and Overhead Packed with neoprene Packing Ring. This Head is now available for 2" or 2½" Tubing to suspend ¾" to 1½" Inner String (Plain or EUE) for Slim Hole operations.



All Hercules Products for Slim Hole Drilling may be purchased through the supply store of your choice. Write for complete information.

HERCULES TOOL COMPANY

Manufacturers of Oil Field Equipment

GENERAL OFFICES AND PLANT • TULSA, OKLAHOMA

Export Representative Oil Field Equipment Co., Inc. 90 West Street, New York, N. Y.

Men in the industry

D. L. Campbell

C. D. Shepard

D. L. Campbell, former senior vice president of **The British American Oil Company Limited,** has been elected to the company's executive vice presidency, and **C. D. Shepard,** general counsel, has been elected to a vice presidency and membership on the board of directors.

Henry H. Beeson has been appointed to the newly created position of natural gas coordinator by **Mobil Oil Company** for company operations throughout the United States. He will headquarter in Dallas. Also, **David K. Taylor** has been appointed manager of **Mobil Producing Tunisia, Inc.** Mobil also announced the appointments of four senior people to **SEREPT,** an oil company with which Mobil has entered a joint exploration venture in Tunisia. The men and their appointments are: **Edwin F. Helser,** exploration manager; **Donald W. MacLean,** senior geologist; **James R. Fasbender,** assistant chief geophysicist, and **John F. Schleinich,** chief seismic interpreter.

C. A. Betzel

Charles A. Betzel has joined **Petroleum Technologists, Inc.,** of Dallas, as technical representative. Betzel will consult with oil company engineers involved in recovery research in the Mid-Continent, Gulf Coast and Rocky Mountain areas.

Eugene S. Coddou has been appointed a patent attorney in the Patents and Licensing Department of **Standard Oil Company (Indiana).**

Nolan Stewart and **Ian Figart** have been appointed as new vice presidents of **Zapata Off-Shore Company.** Stewart is also a vice president and director of **Zapata International Corporation,** and director of Zapata International. Both Stewart and Figart will report directly to **Wayne H. Dean,** executive vice president of Zapata Off-Shore. **J. Porter Brinton** has been named a director of Zapata.

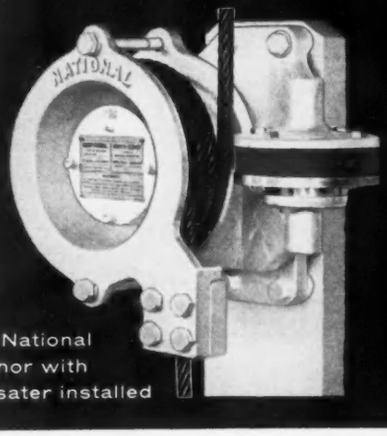
Robert L. McKinnon of **Tidewater Oil Company** has been named employe relations manager of the Southern Division headquartered in Houston.

INTRODUCING

FOR THE SMALL RIG OR PRODUCTION HOISTS

TYPE "G" WEIGHT INDICATOR

The Type "G" is a scaled down version of the Martin-Decker "E," "D," and "FS" Indicators and includes the Sensater mounted in the National Supply Co. Deadline Anchor. This gives the small rigs, workover or production hoists the finest possible instrumentation.



The National Anchor with Sensater installed

MARTIN DECKER

Write for descriptive literature B-P95

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The World's principal manufacturer of Oil Well Drilling Instrumentation

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calls for right decisions . . .

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The manufacturers of CLARSOL, the most widely used drilling Bentonite in the Eastern Hemisphere, offer a comprehensive Mud Chemical supply service with a complete range of approved chemicals and additives from European Sources.

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What you want - where you want - when you want it!

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Men in the industry

R. G. Miller

E. B. Paust

Robert G. Miller and **Einar B. Paust** have been appointed by **Standard Oil Company (New Jersey)** as assistant general counsels.

A. C. Rubel has retired as president of **Union Oil Company.** Rubel will continue active association with the company as a director and member of the executive committee. He will also be available for special assignments.

Alan Beerbower, Dr. Max W. Hill, William H. King, Jr., and **Patrick P. McCall** have been appointed research associates by **Esso Research and Engineering Company.** Also, **James Acquaviva** and **William C. Ludi** have been named engineering associates; **Randolph M. Bailly** was appointed a section head in the process research division and **Frederick J. Hart** was appointed a section head in the products research division.

Dudley P. Penick has been appointed staff gas engineer for **Mobil International Oil Company** in New York. He will have staff responsibility for gas production-separation, processing and utilization in all Mobil International operations.

Paschal Martin

Paschal Martin, petroleum engineer, has recently been employed by the **Ebro Oil Company, Inc.,** Longview, Texas. Martin will assume the duties of chief engineer of that producing oil company.

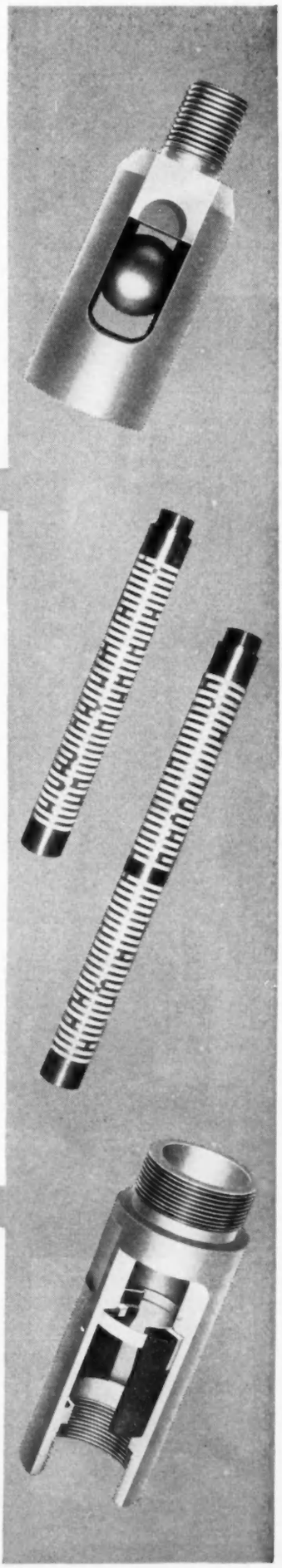
Edwin J. Egan has been named assistant to the general manager of **Mobil Oil do Brazil** in San Paulo, Brazil. Mobil Oil do Brazil is part of **Mobil International Oil Company,** operating division of **Socony Mobil Oil Company, Inc.,** outside the United States and Canada. Egan was assistant to the manager of **Mobil Oil Sudan, Ltd.,** in Khartoum.

Marvin L. Collins has been appointed to the newly created position of assistant to the manager of **Phillips Petroleum Company's** Tax, Insurance and Claims Department.

Let R-u-b-b-e-r Take The Wear

in your sucker rod pumps

It Costs You Less That Way



Both **MARTIN PLUNGERS** and **MARTIN RUBBER GUIDE CAGES** are the result of correct engineering to fully utilize the excellent properties of rubber.

In the **MARTIN SPLIT RINGS,** even the swelling of natural rubber in oil is utilized in sealing the split and tightening the rings in the PLUNGER GROOVES. **Resistance to abrasion** greatly prolongs plunger life in sandy conditions. **Slippery when wet** means that you have lubrication, even when pumping all water. Barrel life is increased because this material cannot score or gall metal.

For the **REPLACEABLE RUBBER GUIDES** in cages, **oil resistant** synthetic rubber is used. No swelling can be tolerated here. **Resilience** completely eliminates the beating action of the ball, and greatly increases ball life. **Resistance to abrasion** reduces wear on both guide and ball.

CUT YOUR COSTS . . . LET RUBBER TAKE THE WEAR . . . Write for our new 1960 catalog.

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Manufacturer

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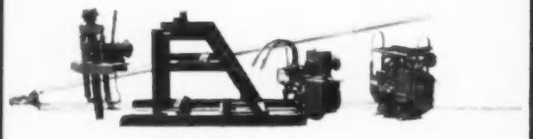

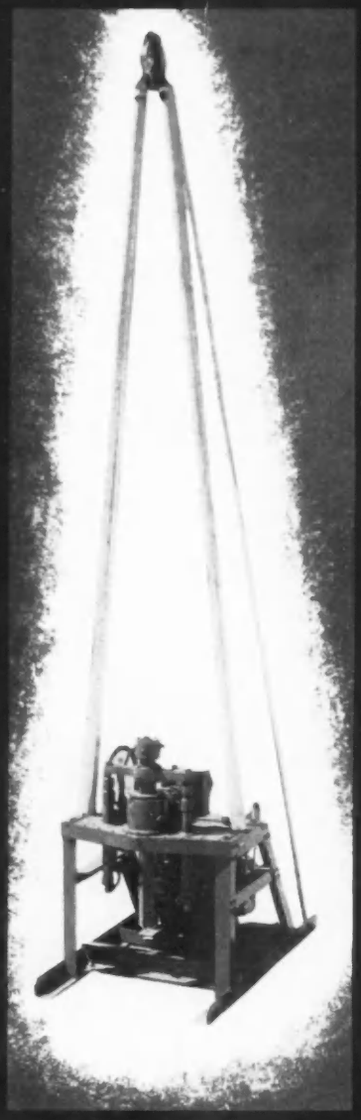

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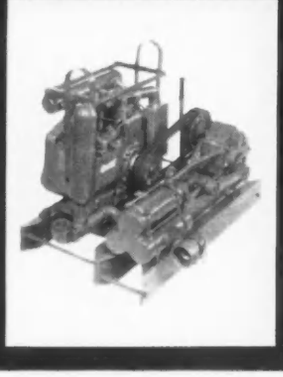
GET ALL THREE WITH A PETTY

Portable Drill

When your operations are obstructed by rough terrain you can get on location and drill the hole you need with Petty's light, powerful, efficient portable drill.

This amazingly versatile drill weighs only 471 lbs., with engine, and can be easily disassembled into just five basic components. No wonder it has become a favorite with oil companies and contractors alike.

Put Petty's Portable Drill to work for you.



Petty

LABORATORIES

317 6TH STREET SAN ANTONIO 6, TEXAS

Men in the industry

B. F. Harrison

H. B. Pier

B. Frank Harrison has been named vice president, finance, and **Herbert B. Pier** controller for **Stekoll Petroleum Corporation.** Other new appointments include **George A. McCulley** who was named secretary, and **Ronald M. Hawkins** who was promoted to vice president and treasurer.

William H. Thorbecke has been appointed assistant manager of the Petroleum Chemicals Division of **Mobil International Oil Company.**

R. F. Higginbotham, assistant division production superintendent for **Sinclair Oil & Gas Company** at Midland, Texas, has been transferred to Houston in the same position for the Houston division. He succeeds **William A. Walther, Jr.,** who was appointed to a similar post with Sinclair's Tulsa Division.

Fuller McCowan

Fuller McCowan has been appointed to the Public Relations Department of **Gulf Oil Corporation** in Houston. McCowan was formerly a member of the company's public relations staff in Pittsburgh.

Kirby Hillin has been named to succeed the the retired **Arch Clark** as division civil engineer for **Sun Oil Company's** Southwest Production Division.

Webb B. Cooley has been named manager of **Mobil Oil Company's** Southwest Ad Valorem Tax Area.

James L. Rumsey has joined **Delhi-Taylor Oil Corporation** in Dallas, as administrative assistant in the Executive Division. He will report to **C. H. Hobbs,** corporate secretary and executive assistant to the president.

Dr. I. Harold Silberberg, formerly with Socony Mobil Oil Company's research laboratories in Dallas, is the new assistant director of **The University of Texas Division** of the **Texas Petroleum Research Committee.**

NEW IDEAS FROM DOWELL

TO HELP YOU MAKE MORE PROFIT

"ACID GUIDE"*

This new companion to the "Frac Guide"* is used by Dowell for *better* engineering of acid treatments. Results have been greater production increases, lower treatment costs, or both. Probable results of acid treatments can be predicted, and the most promising treatment selected for a given well.

CORROSION INHIBITOR SQUEEZE

This Dowell-developed technique for inhibiting corrosion in oil wells has given excellent long-term protection with minimum cost of application. Second and later applications of Corban* inhibitor by "squeezing" it into the producing formation have been even more efficient than the first.

FOAMING AGENT FOR WATER REMOVAL

This new Dowell addition agent can be added to water used in fracturing to induce foaming and reduce swabbing time. It is also used to facilitate air or gas drilling through low-production water zones. For air drilling, it minimizes "balling" of cuttings and creates a foam for easier water removal.

IN SASKATCHEWAN, CANADA. *A well was successfully perforated with Abrasijet after two attempts at explosive perforating had failed.* 4½-inch casing had been cemented through the Mississippian pay from 2318 to 2323 feet. Four perforations were made followed by a frac job. *One month later production was averaging 70 to 80 bopd in a field where most wells average only 50 to 60 bopd.*

IN CENTRAL KANSAS. *A well that produced only water on initial completion was recompleted successfully with Abrasijet.* A radioactive survey showed a channel from initial perforations at about 3318 feet to bottom of casing at 3405 feet. Well was squeezed with cement to shut off water. Abrasijet was used to reperforate without shattering cement. New perforations were from 3323 to 3329 feet. *After acidizing, well tested 6.5 boph with only a trace of water.*

The chances are good that you can increase your profits with Abrasijet. For prompt service or detailed information on Abrasijet, *dial Dowell.* There are 150 offices and stations in the United States, Canada, Argentina and Venezuela. Dowell, Tulsa 1, Oklahoma.

*Dowell Trademark

Services for the oil industry

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DIVISION OF THE DOW CHEMICAL COMPANY

Planning to enter the foreign market?

If so, bring AFIA into your plans *now* to help make sure that your investment and your liability will be soundly protected right from the start. In this way you profit by . . .

. . . AFIA's decades of experience protecting the overseas interests of American leaders in business.

. . . insurance carefully patterned to your business needs and which meets the insurance requirements of the countries where your risks are located.

. . . on-the-scene service and claims settling facilities through 700 offices in 74 countries.

Whether it's a new venture or expansion of your present foreign operations ask your agent or broker to put AFIA on your planning team to protect the security of your business abroad with OVERSEAS INSURANCE unsurpassed.

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Deaths

John B. Hussey, 52, member of the **Federal Power Commission** and former chairman of the Louisiana Conservation Commission, died of a heart attack March 17 while attending the Southern District meeting of the API in San Antonio, Texas.

Barney B. Hayes, 64, independent oil operator and former chief scout for **Skelly Oil Company,** died at his home in Oklahoma City.

William F. Humphrey, 86, president of the former **Tide Water Associated Oil Company,** died February 3.

Aaron M. Weitzenhoffer, 65, co-owner of **Davon Oil and Gas Company,** Oklahoma City, died February 23.

Clarence Raymond Busch, 67, Tulsa, independent oil operator, died February 23.

Marshall Haddock, Jr., 61, Tulsa, independent oil operator, died March 3.

William Erving Bergman, 43, Bartlesville, Okla., senior development engineer for **Phillips Petroleum Company,** died March 9 following a heart attack.

Charles P. Shertzer, 87, Bartlesville, Okla., retired independent oil operator, died March 18.

PERFORATE TUBING IN THE WELL

KINLEY TUBING PERFORATOR

J. C. Kinley Co. Licensees

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Anzoategui Wire-Line Service, C. A.
BAY CITY, TEXAS—J. P. Graham . . . . . CI 5-4526
CABIMAS, ZULIA, VENEZUELA
Wireline Engineers, S. A.
CASPER, WYOMING—C. A. White 3-5264
CORPUS CHRISTI, TEXAS—Tolle, Inc. . . TE 5-5367
CORPUS CHRISTI, TEXAS
J. D. Ball Wire Line Service Co. . . . . TU 3-7762
FARMINGTON, NEW MEXICO
B & R Service, Inc. . . . . DA 5-2393
FORT MORGAN, COLORADO—C. A. White 919
GLENDIVE, MONTANA—C. A. White . . EM 5-3833
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Assoc. Eng. & Equip., Inc. . . . . UP 2-0347
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Fred Haynie Oil & Gas Well Service . . . UP 3-7885
HOUSTON, TEXAS
Mid-Western Well Ser. Co. . . . . RE 4-4262
HOUSTON, TEXAS
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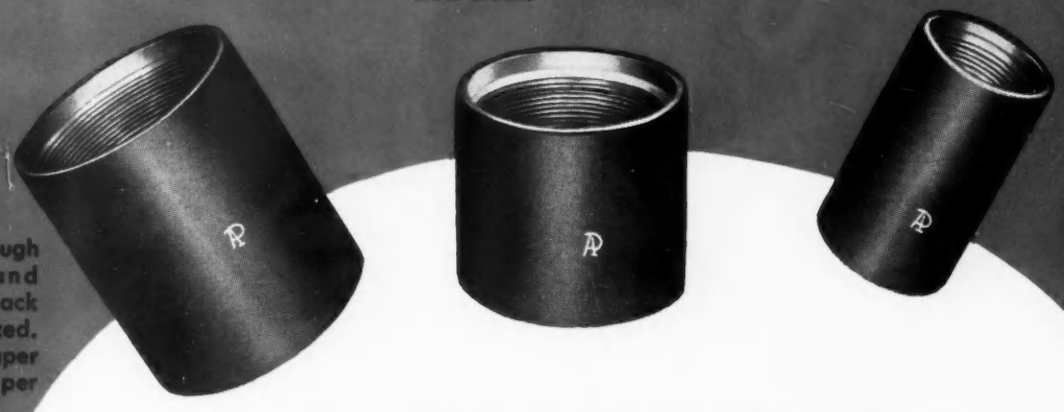
LAFAYETTE, LOUISIANA—Camco, Inc. . CE 5-3124
LIBERAL, KANSAS—Rainbo Service . . . Main 4-3598
MIDLAND, TEXAS
Luccous Service & Eqpt. Co. . . . . MU 2-8311
NEW IBERIA, LOUISIANA
Cardinal Wireline Specialists, Inc. . . . . EM 4-5165
NEW IBERIA, LOUISIANA
Klein-Deco Wire Line Service . . . . . EM 9-6632
ODESSA, TEXAS
Camco Wire Line Service, Inc. . . . . FE 2-6497
ODESSA, TEXAS
John Kuykendall Wireline Service Co. . . FE 7-7210
OKLAHOMA CITY, OKLAHOMA
Rainbo Service Co. . . . . ME 4-2131, ME 4-0105
PETTUS, TEXAS
Eddie Jones Eng. Co., Pettus 16, Beeville . FL 8-1218
SHREVEPORT, LOUISIANA—Camco, Inc. . . 8-3615
VICTORIA, TEXAS—Camco, Inc. . . . . HI 3-9521
WICHITA FALLS, TEXAS—Tudson-Eads, Inc.
322-8584, 322-1792, 767-8727, 723-4690, 767-3793

A. P. I. CASING COUPLINGS
Short and Long, sizes 4½" through 13⅜". All threads 8 round, ¾" taper tapped per foot. Combination and sharp V thread casing couplings also available from stock.



A. P. I. LINE COUPLINGS
Sizes ⅛" through 12", 14" and 16" O.D. Black and Galvanized. Recessed, Taper Tapped ¾" per foot.

A. P. I. TUBING COUPLINGS
Non-Upset sizes 1.900" through 4½". Upset sizes 1.660" through 4". Grades J-55, N-80 and P-105.

ALL SIZES AND TYPES OF

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STANDARD MERCHANT
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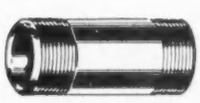
3000# and 6000# FORGED STEEL COUPLINGS
Manufactured to ASTM specification A-#105. Available in full and half couplings. 3000# sizes ⅛" through 4". 6000# sizes ⅛" through 3".

USE WITH THESE DEPENDABLE CAPITOL FITTINGS

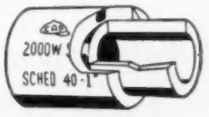


NIPPLES

UNIONS

SQUARE HEAD PLUGS

HEX HEAD PLUGS



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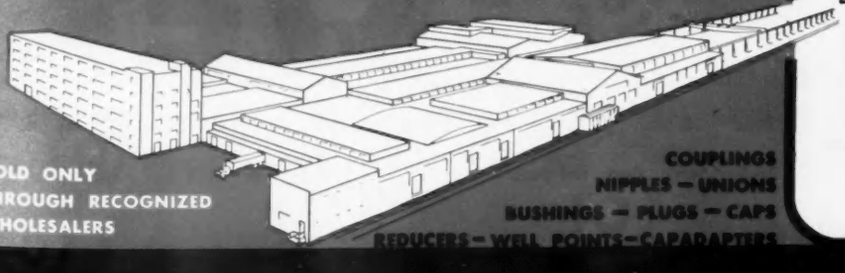
PRODUCERS OF QUALITY FITTINGS FOR MORE THAN 30 YEARS



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CAP CAPITOL
MANUFACTURING CO.
DIVISION OF HARSCO CORP.
COLUMBUS, OHIO

Associations

API Southern District Names Officers, Presents Service Awards

Jack P. Robbins (second from left), division manager in San Antonio, Texas, for Skinner Corporation was elected district chairman of the American Petroleum Institute's Southern District for 1960, at the district meeting recently in San Antonio. Other officers elected include (left to right): Marvin Rogers, Allen & Morris Drilling Company, San Antonio, vice chairman for Balcones Area; Robbins; Raymond Perry, Union Producing Company, Shreveport, La., vice chairman for Ark-La-Tex area; W. L. Massey, Mining Division, Aluminum Corporation of America, Port Lavaca, Texas, vice chairman for South Central Texas; Walter Kaltayer, Hunt Drilling Company, Corpus Christi, Texas, vice chairman for Southwest Texas, and A. L. Vitter, Jr., The California Company, New Orleans, chairman of the District Advisory Committee. Vitter is the outgoing district chairman. Not shown is Paul Clinkonbeard, Dow Chemical Company's Dowell Division, Shreveport, who was elected district secretary-treasurer, succeeding Robert A. Buschman, Field Drilling Company.

L. E. Fitzjarrald, Phillips Petroleum Company and API vice president for production, presented the API Citation for Service to four oil men for outstanding service in API assignments. The awards were presented at the recent API Southern District Meeting. Those receiving the awards were (left to right): Tom W. Keating, drilling consultant of Dallas; Jack P. Robbins, newly elected chairman of the southern District; Fitzjarrald; Ben F. Carter, Union Producing Company, Shreveport, La.; C. H. Taylor, Shell Oil Company, Houston, and Roy F. Bobo, Southeastern Drilling Company, Comodoro Rivadavia, Argentina, who accepted the award for his father, Roy A. Bobo.

W. C. NORRIS VALVES

Field Tested and Approved
150 psi working pressure

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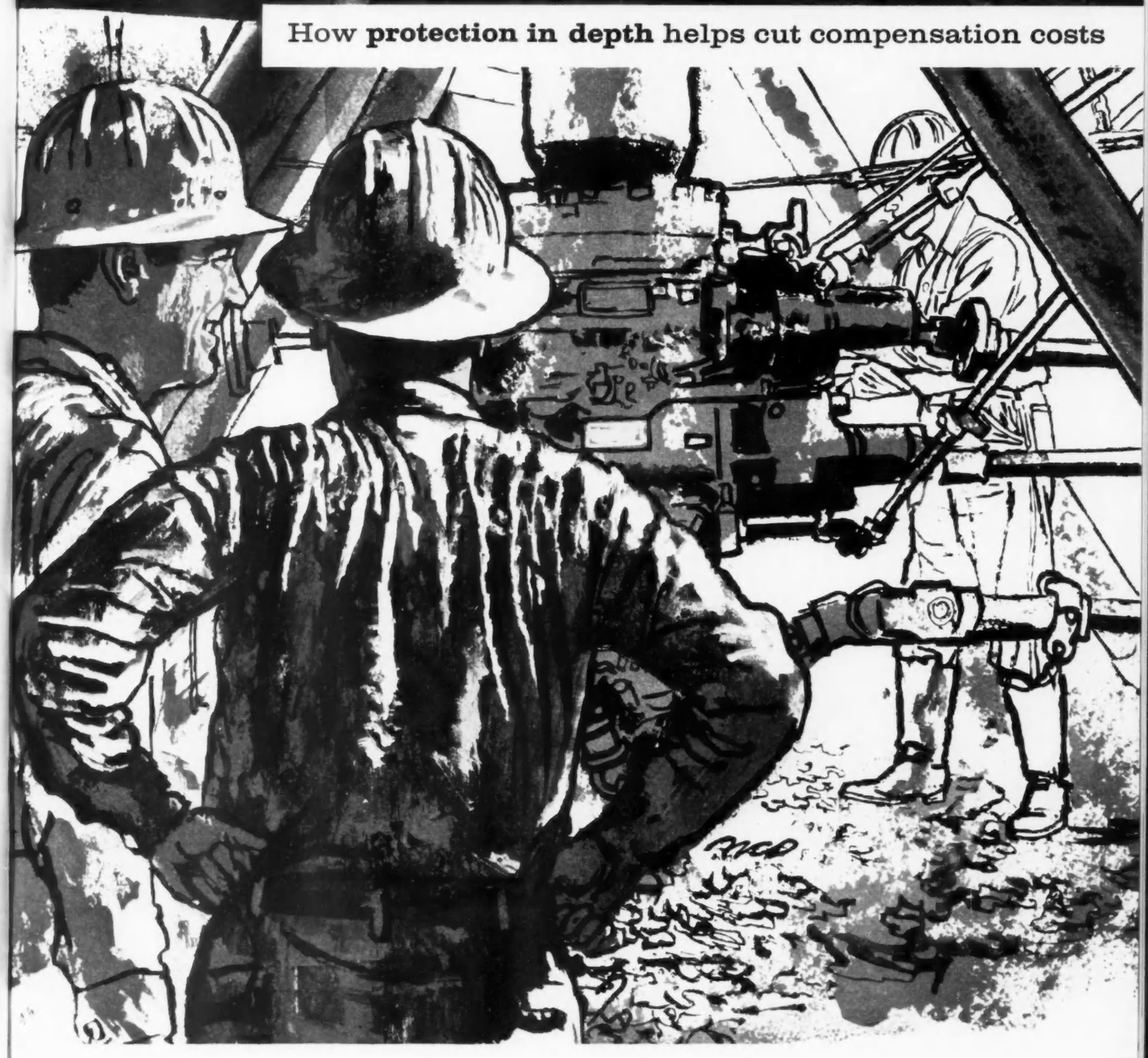
How **protection in depth** helps cut compensation costs



How well are your men equipped to handle a blowout?

A well that kicks can be the forerunner to disaster. How swiftly and effectively your crew on tour reacts largely determines the outcome. Are these men trained for a blowout emergency? Liberty Mutual engineers help the pusher and drillers in their training program. They check blowout preventers, fire protection equipment and review the emergency procedures. This thorough check-out is but one of the many Liberty Mutual services that add up to protection in depth. To learn more about Liberty's protection in depth and how it can help lower your business insurance costs, just get in touch with the Liberty Mutual office nearest you.

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Mohammed and his Ruston turbines

Mohammed ibn Rajih Mohammed, leading engine room operator, checks gauges on one of the two Ruston gas turbines at Nariya pump station which is on the pipeline system that transports oil from Aramco installations to the Tapline terminal at Sidon, Lebanon. Many Ruston gas turbines are now operating on Aramco's pipelines in Saudi Arabia.

To Nariya came two Ruston gas turbines . . . and Mohammed ibn Rajih Mohammed found himself in control of industrial power, in its most advanced form. But Mohammed, who is now leading engine room operator at the Arabian American Oil Company's Nariya pump station in Saudi Arabia, soon recognised the simplicity of operating a Ruston gas turbine . . . that's just one of many features of these turbines which have made them so popular with oilmen from the Middle East to the Americas.

RUSTON gas turbines

up to 1260 b.h.p. at 80° F. ambient temperature.

For electricity generation, pipeline-pumping, and gas boosting in the petroleum industry . . . for burning natural gas, distillate fuels and selected crudes.

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Associations

Head Geophysical Society

The Southwest Louisiana Geophysical Society recently elected the following officers: (Front, left to right) Dick Hollenbaugh, Petty Geophysical Engineering Company, vice president, and Walter Hurt, Sohio Petroleum Company, president. Above (left to right) R. Ned Pratt, Sun Oil Company, treasurer, and Lucius Geer, Union Oil Company of California, secretary.

Liberal Geological Society Elects Zimmerman President

Dick Zimmerman, with Petroleum, Inc., in the Panhandle district, has been elected president of the Liberal Geological Society at Liberal, Kan.

Zimmerman's associates are Russell Clausen, Panhandle Eastern Pipe Line Company, vice president; Larson Drake, The Ohio Oil Company, treasurer, and John Mason, Pan American Petroleum Corporation, secretary.

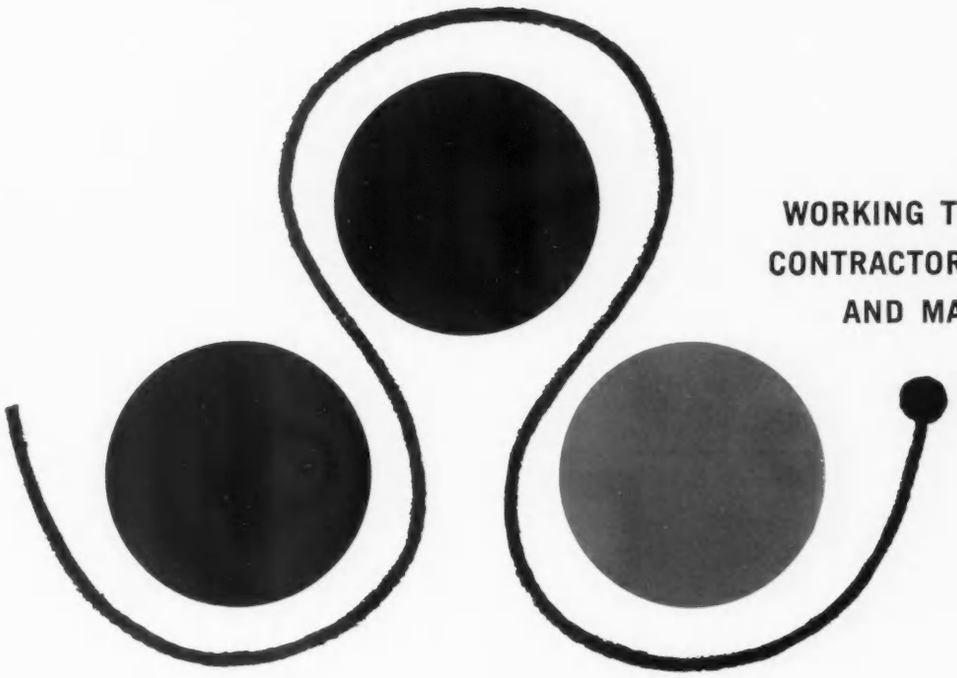
Wayne E. Glenn Named President of SPE of AIME

Wayne E. Glenn, Houston manager of Continental Oil Company's Production Department, has been installed as the new president of the Society of Petroleum Engineers of the American Institute of Mining, Metallurgical, and Petroleum Engineers, Inc., for 1960. Glenn succeeds John S. Bell, Houston, production manager, Gulf Coast Division, Humble Oil & Refining Company. President-elect will be Earl M. Kipp, San Francisco, special consultant on producing problems on the staff of the vice president in charge of producing, Standard Oil Company of California, nominated to take office in 1961 as SPE president.

Basil P. Kantzer, Los Angeles, vice president in charge of exploration and production, Union Oil Company of California, former president of SPE, and John P. Hammond, Tulsa, assistant general superintendent, Production, Amerada Petroleum Corporation, former president of SPE, have been named as new vice presidents of AIME.

Herbert F. Beardmore, Houston, manager, Gulf Coast District, Gulf Oil Corporation, is one of the new AIME Directors.

In the SPE, new vice presidents will be R. A. Morse, Pittsburgh, associate



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CONTRACTOR, PRODUCER,
AND MAGCOBAR

plan mud programs for pay and profit

High drilling costs can be cut by efficient use of drilling fluids. The right drilling chemicals, **used right** by Magcobar engineers, can help increase penetration rates, save on trips and bits, reduce materials needed, and save on equipment and manpower.

But, to make sure that the mud program is the most efficient, it must be planned from the beginning. And, because it must deal with so many specifics, it can be developed only with the close cooperation of producer, contractor, and Magcobar engineer. A sound mud program must be based on product performance, formations to be drilled, and, very important, type of equipment to be used.

By working together, a planned mud program can be developed to make full use of the money-saving advantages of Magcobar Technology. This Technology formulates special drilling fluids to reduce or prevent damage to the pay, resulting in quicker completion, higher production, and less need for expensive stimulation work. Magcobar Technology can help you as a contractor to drill wells more cheaply, can help you as a producer to have better wells. Drill your next wells with Planned Mud Programs with Magcobar.

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WELL DONE
WITH
MAGCOBAR
TECHNOLOGY

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Complete
DRILLING MUD SERVICE

AGNET COVE BARIUM CORPORATION HOUSTON

director, Gulf Research & Development Company, and William D. Owsley, Duncan, Okla., senior vice president, Halliburton Oil Well Cementing Company.

New SPE Directors will be A. E. Collins, Wichita, Kan., vice president and production manager, Vickers Petroleum Company; Robert L. Hoss, Denver, petroleum consultant; Harold J. Maiers, Caracas, Venezuela, chief petroleum engineer, Socony Mobil Oil Company de Venezuela, and J. E. Russell, Abilene, Texas, president, Russell Engineering.

Past NOMAD Regents Awarded Diamond Pins

NOMADS who had served for two or more terms on the National Board of Regents were presented with diamond lapel insignias at the Twenty-First Annual Inaugural Ball of the Los Angeles Chapter of NOMADS.

Past NOMADS regents who received the diamond insignias were W. F. Bettis of Johnston Testers, Inc.; Henry Pullman, Baker Oil Tools, Inc.; Bob Eiche, R. J. Eiche & Associates; Ted Sutter of Baker Oil Tools, Inc.; Robert P. Gaylord, Wagner-Morehouse, Inc.; W. A. Wilson, Web Wilson Oil Tools, Inc.; Earle Boggess, Baker Oil Tools, Inc.; Lee Laird, Ladish Pacific Division; John Flanagan; Harry Hester, McCullough Tool Company; Elmer Decker, Martin-Decker Corporation, first regent of the NOMADS; Roland E. Smith, Roland E. Smith Company, and J. A. Engstrand.

M. W. Haas Named Speaker At Log Analysts Meeting

Merrill W. Haas, vice president of Humble Oil & Refining Company (Carter Division), Tulsa, will be the keynote speaker at the coming annual meeting of the Society of Professional Well Log Analysts which will be held in Tulsa May 15-17. Haas has entitled his talk "Log Analysts Are Important People."

M. W. Haas

Haas attended Kansas University, University of Michigan, and Harvard University.

Simpson and Decker Named To New IPAA Committee

Gordon Simpson, president of General American Oil Company of Texas, Dallas, has accepted the chairmanship of the Independent Petroleum Association of America's new Ways and Means Committee, which will study the causes of depressed conditions in the domestic oil industry.

Harold Decker, president of Highland Oil Company, Houston, will serve as vice chairman of the 42-man committee which is made up of oil men representing the major producing areas of the nation.

The new IPAA committee held its first session at the association's midyear meeting, April 25-26 in Denver.

H. G. Vesper to Be Speaker At Spring API Meeting

Howard G. Vesper, president and director of Standard Oil Company of California, Western Operations, Inc., will make the management address at the Thirty-Third Annual Pacific Coast American Petroleum Institute District Spring Meeting. His management address will be presented Thursday, May 12.

Vesper began his career with Standard in 1922, after graduating from California Institute of Technology. He became company president in 1958. Vesper was recently elected president of the Western Oil and Gas Association for 1960.

The 1960 annual Spring Meeting, Pacific Coast District, API, Division of Production, will be held May 12-13 at the Biltmore Hotel, Los Angeles. J. N. Gregory, Teredon Company, is district chairman.

MODERN ENGINEERED GAS LIFT VALVES

Guaranteed Low Cost Maintenance

A Harold Brown Gas Lift Valve is available for every type Gas Lift Installation.

H-B Gas Lift Valve Features:

- Large Dome Capacity
- Stops limit stem travel, protect bellows
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Normally Closed Check Valves

Three interchangeable types:

- Magnetic cage check valve
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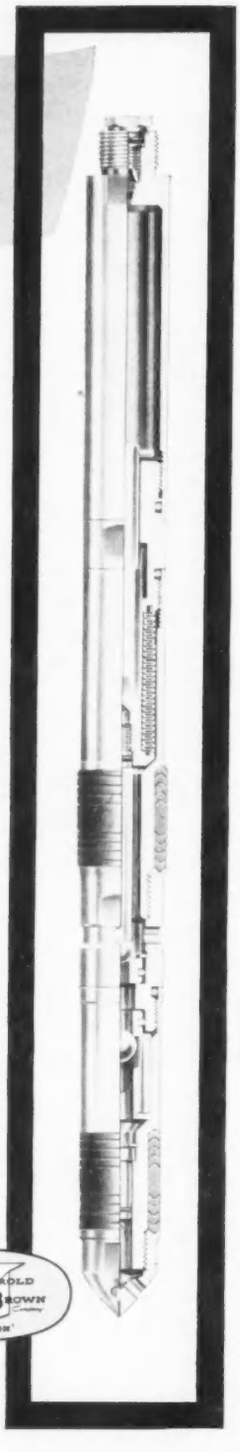
These Superior Features and the Long Wear of H-B Check Valves Make This Possible!

GUARANTEED EXCHANGE POLICY FOR STANDARD VALVES

1 year in hole—full warranty against mechanical defect.
2 years in hole—Exchange $25.00
2 to 3 years in hole—Exchange $35.00
3 to 5 years in hole—Exchange $50.00

Slight additional cost for retrievable valves. Also five dollars additional cost outside mid-continent areas.

Ask your Harold Brown Representative for full information on putting highly efficient, low cost H-B Gas Lift Valves in your wells.



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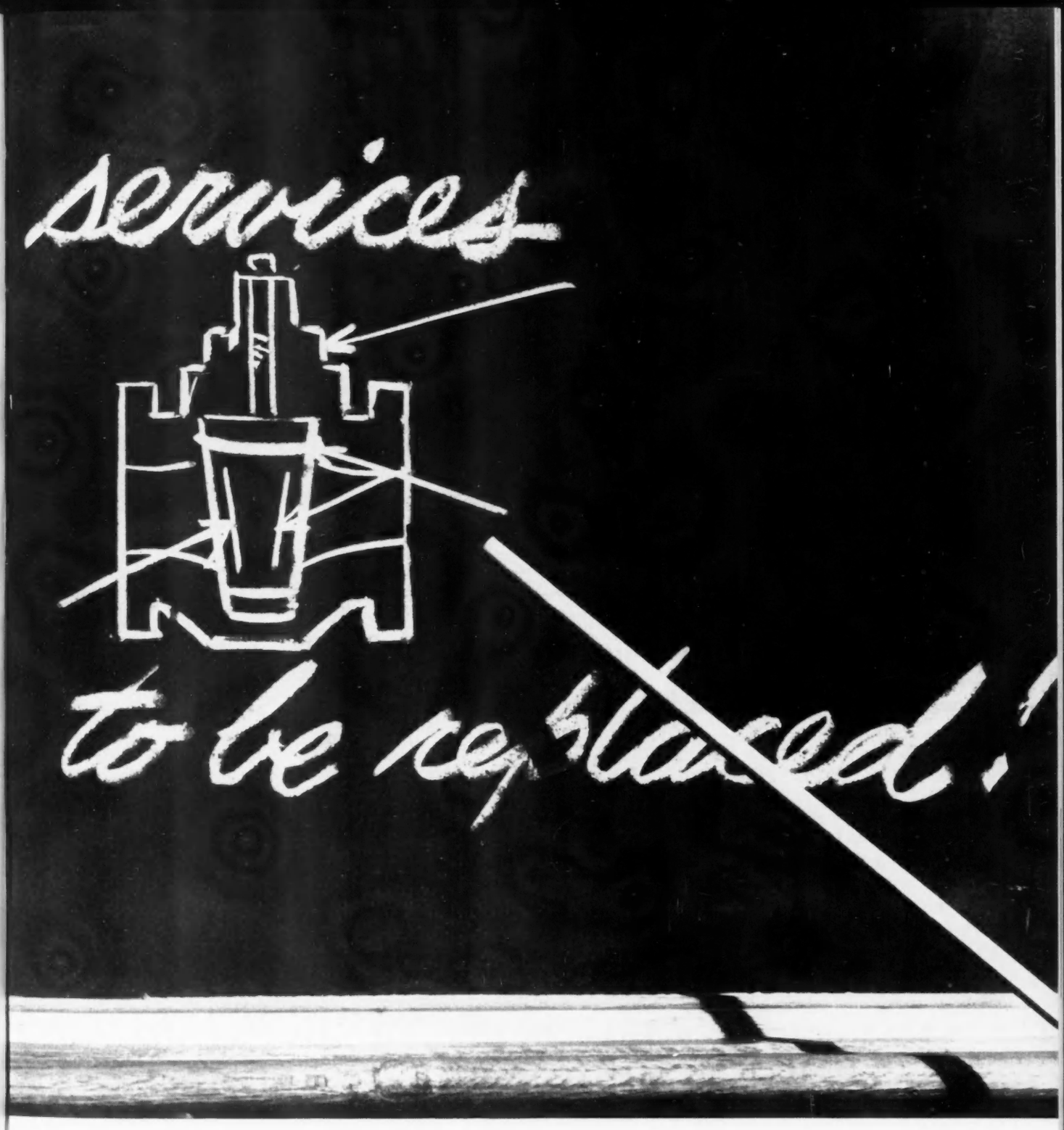

cation largely eliminates the *causes* of valve failure. How much would you save if you had a valve that never needed to be replaced — or that outlasted your present valves by ten or twenty times? Try just *one* Rockwell-Nordstrom Valve on your toughest service. *Rockwell Manufacturing Co., Pittsburgh 8, Pa. Canadian Valve Licensee: Peacock Brothers Ltd.*

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another fine product by

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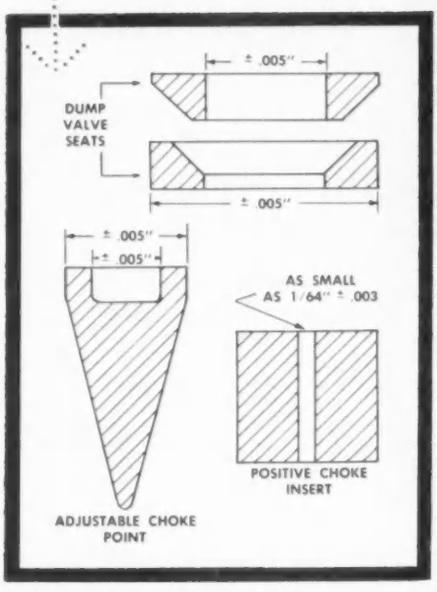
difference . . . . . .

WEAR IS WASTE!

Here's How CMC Hard-Trim Can Trim Your Operating Costs



Impingement of abrasive oil and gas flow on control valves and orifices causes rapid wear, frequent lost production for maintenance and repair. A few dollars invested in precision-cast tungsten carbide hard-trims for these troublesome wear spots can save you hundreds or thousands in down-time.

CMC Tungsten Carbide Castings are not to be confused with conventional hard-facing materials or sintered carbides. They are *cast* to extremely close tolerances and provide a density and wear resistance not available in other materials.

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WRITE TODAY FOR COMPLETE DETAILS AND LIST OF HARD-TRIM SUPPLIERS

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Suppliers' notes

Plastic Applicators Looks Ahead

A program of development for 1960 was outlined to sales engineers and executives of Plastic Applicators, Inc., at the company's winter conference held recently in Houston. Present for the conference were: (front row) Cordell Garner, vice president in charge of sales; G. J. Duesterberg, president; (second row) Harry Bozeman, Pipe Inspectors; Vic Hajovsky, vice president in charge of Houston operations; Pat Donnelly, Houston sales; (third row) Gerald Beard, Corpus Christi, Texas, sales; Cam Murchison, Tulsa sales, and Bill Kristymik, Houston sales.

Dow Warren

J. A. Grundy

Dow Warren, J. A. Grundy and **J. O. Winston, Jr.,** have been elected directors of **Reed Roller Bit Company** and **William E. Scarborough** was elected vice president of sales. Warren first joined Reed in 1936 as an engineer in plant engineering, later becoming plant engineer. Grundy joined Reed in 1937 as an engineer, left the company in 1939, but returned in 1942. Scarborough was appointed domestic sales manager of Reed in 1959. He joined the company in 1936.

W. E. Scarborough

R. N. Waters was recently elected to the position of secretary-treasurer of **Baker Oil Tools, Inc.** He replaces **J. E. Rosenlind,** who has been with the company in various managerial positions for nearly 32 years and will continue to serve in an advisory capacity.

John V. Glaves, assistant district sales manager, mechanical goods, Houston branch of **United States Rubber Company,** has been promoted to district sales manager, effective immediately. Glaves replaces **J. Wesley Batton,** district manager since 1951, who has retired from the company after nearly 33 years of service.

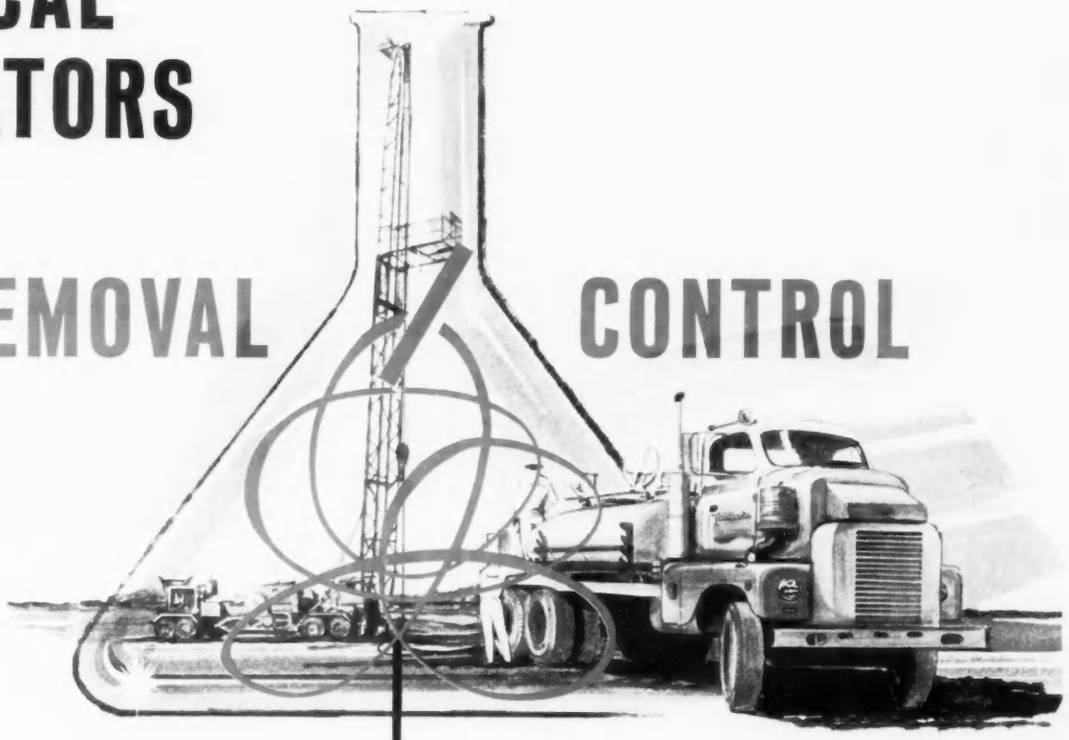
R. B. (Cocky) McCannon has been promoted to the position of Northern California District manager for **Baker Oil Tools, Inc.** Also, **H. L. (Hap) Hanright,** formerly Southern Rocky Mountain District manager in Denver, was promoted to the position of Training and Sales Promotion supervisor in Los Angeles. **K. J. (Ken) Kurtz** will be director of the recently consolidated Northern and Southern Rocky Mountain districts. He will headquarter in Denver.

Edgar (Ed.) Herbst has been transferred to Dallas as resident sales representative for the **Geo. E. Failing Company.** Herbst formerly worked out of the Houston office.

Noel D. Morris has been named manager of the new Well Drilling Machinery Division at **Alten Foundry and Machine Works, Inc.** Morris was formerly sales manager of the Loomis Machine Company of Tiffin, Ohio.

Tracey E. Smith was elected president, general manager and a director of **National Tank, Ltd.,** Calgary, Alta., Canadian subsidiary of **National Tank Company** of Tulsa. Other appointments include **A. H. vanderLee,** Vice president, assistant general manager and a director; **W. A. Law,** assistant secretary-treasurer.

CHEMICAL ACTIVATORS FOR GYP REMOVAL CONTROL



REMOVE GYP CHEMICALLY!

Halliburton's *new Gyp Removal Solution* is designed to penetrate normally insoluble gyp scale (calcium sulphate) . . . and convert it into an acid soluble scale which can be removed by conventional acid treatments. This remarkable advance helps eliminate the costly task of pulling tubing to remove scale.

CONTROL GYP CHEMICALLY!

Scalechek is Halliburton's technique of placing SCP materials, scale control polyphosphates, into a producing formation to help provide protection against gyp deposits and other scales for extended periods of time at temperatures up to 260°F. Scalechek materials may be injected in conjunction with a fracturing operation . . . or it may be injected without sand.

These two chemical processes are now in wide use as a part of Halliburton's continuing program of providing the Petroleum Industry with fast, efficient help . . . anytime . . . any place it is needed. Your local Halliburton Representative is your link to this chain of service. Contact him on your next job calling for creative chemistry.

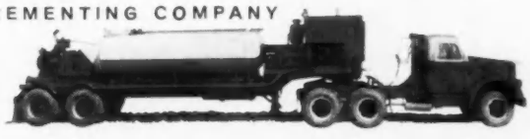
REMOVE GYP CHEMICALLY!

CONTROL GYP CHEMICALLY!

"Continue to Look to Halliburton for Leadership."

HALLIBURTON CHEMICAL SERVICES

HALLIBURTON OIL WELL CEMENTING COMPANY DUNCAN, OKLAHOMA



Suppliers' notes

V. C. Horner, vice president of **Byron Jackson Division of Borg-Warner Corporation,** has been named to the newly established post of operations manager of the Jet Process Section of this division.

A. C. Polk has been appointed executive vice president and general manager of **Dowell Division** of **The Dow Chemical Company.**

J. R. Paul, operations manager at Evansville, Ind., for **Dowell Division of Dow Chemical Company,** has joined the company's general office sales office in Denver.

F. C. Brechtel

J. Alliger

Fred C. Brechtel has been elected executive vice president and a director, and **Jerald Alliger** was named vice president and a director of **Geophoto Services, Inc.,** of Denver.

RESERVE YOUR SPACE **NOW!**

PERMIAN BASIN OIL SHOW

The 1960 Permian Basin Oil Show will be the largest oil exposition this year. It's your opportunity to exhibit your products or services right in the heart of the oil country directly to the men that use and buy those products.

Be sure your company is represented. Act now for choice space. For complete information write:

Jay Alvey, Manager
Permian Basin Oil Show
P. O. Box 2248
Odessa, Texas

Warren R. Kenefick has been named sales engineer **Edward Valves, Inc.'s,** line of high pressure, high temperature forged and cast steel valves in the Southeast District. Edward Valves, Inc., is a subsidiary of **Rockwell Manufacturing Company.**

Charles Welch of Wichita Falls, Texas, and **Richard White** of Dallas, have been selected for the Axelson sales training program, **Axelson Division of U.S. Industries, Inc.**

John W. Mays has been appointed field representative for **U.S. Steel's Oil Well Supply Division** in Houston.

Cyrus V. Helm has been named administrative assistant to **Walter Beadle,** executive vice president of **The Western Company.**

Harry T. Phelps has been appointed industrial tractor and equipment sales representative for **International Harvester Company.**

Maurice Martin has been named executive vice president of **Geopetrole of Paris, France,,** a consulting firm specializing in formation evaluation and reservoir engineering.

Ed Neely

Ed Neely has been appointed sales engineer for the Oil Tools Department of **Avondale Marine Ways, Inc.** Neely will be located at the Oil Tools Department of Avondale's Harvey "Quick Repair" on the Harvey Canal in Harvey, La.

J. F. Powers, Jr., has been appointed vice president and sales manager of **Chiksan Company.** In his new position, Powers will move from Chiksan's eastern office in Newark, N. J., to Brea, Calif., where the firm's headquarters are located.

Brooks Doughtie has been named district sales representative handling both domestic and export sales in the Tulsa office of the **Baash-Ross Division of Joy Manufacturing Company.**

William E. Korsan has been appointed assistant manager and **Paul W. Clark** as manager of sales of the Industrial Systems Department of **Allis-Chalmers Manufacturing Company.**

Carl Rush, chairman of The Spindletop Section of petroleum engineers, has been appointed district sales engineer for **McMurray Oil Tool Specialties.**

Richard B. Hazard, vice president of **Raybestos-Manhattan, Inc.,** has been re-elected president of the **Mechanical Packing Association, Inc.**

Suppliers' notes

W. C. Meeks

W. C. (Bill) Meeks, sales representative for Chicksan-Weco oil products for **Well Equipment Mfg. Corp.** has been transferred from Denver to Dallas to serve the Dallas-North Texas area. Meeks has been representative in the Rocky Mountain area for the past two years.

John J. Boslet has been appointed store manager at Greensburg, Ky., for **U.S. Steel's Oil Well Supply Division.**

Wayne Overman has been named district manager for the **Tuboscope Company's** Shreveport, La., district. Overman will manage the company's sales and service for the entire state of Arkansas and North Louisiana.

F. L. (Bud) Bryan has been promoted to director of personnel relations for **Schlumberger Well Surveying Corporation.** Bryan began with Schlumberger in 1941. **Charles B. (Chuck) Evans** has been appointed Permian Basin Division manager, and **Ralph P. Burton** was named the new Northern Rocky Mountain Division head.

Zeb Lano

Zeb Lano has been appointed sales representative at Electra, Texas, for **Bradford Motor Works** of Corry, Pa. Lano was formerly field representative for National Supply Co. at Pampa, Texas, and has over nine years experience in oil field work.

W. T. (Tex) Smiley has been named national service manager for **General Electric's** mobil radio at the company's Communication Products Department factory headquarters in Lynchburg, Va.

Roy C. Ingersoll, chairman of the board of **Borg-Warner Corporation,** was elected a senior board member of the **National Industrial Conference Board** for a term of three years at the board's meeting in New York City.

Jim Flemmons has been promoted to the position of assistant to the general manager of sales for **Cardwell Manufacturing Company, Inc.**

D. B. Scott has been appointed to succeed **F. C. Ludington,** who retires July 1, as manager of the Control Department at **Allis-Chalmers Manufacturing Company.**

John V. Glaves, an assistant district sales manager for mechanical goods at the Houston branch of **United States Rubber Company,** has been promoted to district sales manager.

James B. Allen, Jr., is the new store manager at Williston, N. D., for **The National Supply Company.** He succeeds **Dwight A. Reams,** who transferred to Denver as a city sales representative. Also, **Philip R. Adkinson** was named store manager at Kevin, Mont., succeeding Allen, and **Jack Lee Radden** was appointed store manager at Glendive, Mont., replacing K. M. Kennedy, who transferred to the Williston store.

Kemp Barley has been added to the sales staff at **Oil Base, Inc.,** of Compton, Calif. Two years ago Barley sold the interest in his own mud company in California and went to Denmark as head drilling engineer for Kellog Overseas Drilling Company. Barley will be stationed in Bakersfield, Calif., to serve the San Joaquin Valley for Oil Base, Inc.

Kemp Barley

This 18-hp Model THD 2-cylinder Wisconsin power unit is equipped with clutch take-off, belted to a Roper rotary pump with a capacity of 60 bbls. of crude oil at 200 psi.

Here's **ENGINE POWER**
tailored for your isolated installation

Operating in the "Four Corners" area of northwestern New Mexico, this Wisconsin-powered pipeline unit was selected by a major crude oil purchaser because of previous experience in Southwest Texas, Wyoming, and Canada. They were *pre-sold* on the self-sustaining dependability of Wisconsin Engine Power, working under rugged conditions in hot, remote regions.

The Wisconsin Heavy-Duty Air-Cooled Engines are "tailor-made" for this type of operation. Dual carburetion enables the engine either to operate on gasoline or to run "off the land," using natural gas. Stellite exhaust valves and valve-seat inserts and positive rotators increase valve life 200% to 500%.

Exceptionally efficient AIR-COOLING at all temperatures from low sub-zero to 140° F. licks the cooling problem anywhere, at any season. Heavy-duty design and construction in all details is your unwritten guarantee of long engine life and low-cost maintenance. Basic high torque provides the load-lugging power that keeps the engine rolling regardless of load variations.

You can't do better than to specify "Wisconsin Power" for your oil field utility units. Write for engine bulletin S-249. J-154

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WRITE TO HARLEY SALES CO.
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Oil Field Distributors for Wisconsin Engines and all types of Utility Units

World's Largest Builders of Heavy-Duty Air-Cooled Engines

For more data on advertised products, use Readers' Service Cards, last page

Suppliers' notes

William E. Ridgeway has joined **Byron Jackson Tools, Inc.,** as field representative for the Near and Middle East areas.

Harold Grant has been named regional training supervisor for **Halliburton Oil Well Cementing Company's** southern region—its Houston, Corpus Christi, Texas, Shreveport and New Orleans divisions.

Admiral Lewis L. Strauss and **J. Richard Scanlin** have been elected directors, and **Arthur E. Martin** was named a vice president, Traffic Department, for **General American Transportation Corporation.**

Look at a JENSEN this way . . . .

Oil production and profit records make a JENSEN look like this . . .

The low cost and operation of a JENSEN make it look like this . . .

Chances are *your* profit picture isn't as large as it would be if you standardized on JENSENS. Let us show you why!

STOCKED BY YOUR LOCAL SUPPLY STORE

Made by JENSEN BROS. MFG. CO., INC., P. O. Box 477-D, Coffeyville, Kansas
Export Office: 250 Park Avenue, New York 17, N. Y.

JENSEN JACKS

New Canadian Representative

G. B. (Sha) Schapaugh, vice president and sales manager of Frank W. Murphy Manufacturer, Inc., and Duane Schmeeckle, head of Petro-Automation Industries, Ltd., of Calgary and Edmonton, Alta., study a map at the conclusion of their agreement whereby Petro-Automation will represent the Murphy Company in Canada. Petro-Automation will maintain complete stocks and offer engineering service on applications of Murphy Safety Switches to oil production and pipe lining.

Thomas A. Hopkins has been appointed sales representative-store area at Mirando City, Texas, for the **Oil Well Supply Division of U.S. Steel Corporation.**

Earl Barkley has been appointed area sales manager of the newly formed Rocky Mountain Area offices of the **Baash-Ross Division of Joy Manufacturing Company.**

George A. Peck has been appointed to the presidency of **Southwestern Industrial Electronics Company,** of Houston, one of the Dresser Industries. Peck comes to SIE from the Stromberg- Carlson Company of Rochester, N. Y., where he was vice president and general manager of the Electronics Division.

George A. Peck

G. W. Carrington, vice president, **Exner-Dodge, Inc.; William F. Gates,** vice president, **Black, Sivalls & Bryson, Inc.,** and **R. O. Hambric,** general merchandise manager of the **Continental-Emsco Company,** have been named members of the **National Defense Executive Reserve for Oilfield Equipment and Services.**

Alberto M. Vasquez has been added to the sales representation staff in South America as an acting agent for **Cameron Iron Works, Inc.** Vasquez' company is **Equipo Petrolero, Ltd.,** in La Paz, Boliva.

E. S. McRoberts has been appointed district manager of the Tulsa office of **The J. B. Beaird Company, Inc.** McRoberts has been associated with Beaird since 1944.

Suppliers' notes

B. W. (Bill) Bourne has been appointed a vice president of **Delta Tank Mfg. Company, Inc.** Bourne had been sales manager of Delta's Oil Field Equipment Division in Houston.

B. H. Pickard has been appointed administrative assistant on the executive staff of **G. J. Duesterberg,** president of **Plastic Applicators, Inc.,** of Houston. Pickard's work will be concerned with the parent company, **Plastic Applicators, Inc., Rubber Applicators, Inc.,** and **Pipe Inspectors.**

B. H. Pickard

James W. Dees, former store manager at Houma, La., for **Continental-Emsco** has been promoted to district manager for the Lafayette, La., office. At the same time, these promotions were also announced by Continental-Emsco: **Leo R. Walker,** former store manager at Lake Charles, La., has taken over merchandising duties for the South Louisiana Division office; **Al L. Beavers,** former Houston District Production Machinery specialist, is now in charge of merchandising for the Houston Division; **Douglass P. Yadon, Jr.,** is the new Division Oil Country Tubular representative for the Tulsa Division, and **Dwight G. Barnhart** is the new District Tubular representative located in Columbus, Ohio; **Ennis Winford Smith,** El Dorado, Ark., **James E. Yarrough, Jr.,** Duncan, Okla., **B. R. Grieve,** Houston, and **Winfred L. McWhorter,** Luling, Texas, have been promoted to D+B Pump specialists; new men in the position of store managers are **Kermit A. Holden,** Leeville, La., and **Nealy Nevils, Jr.,** Lake Charles, La. **T. C. Williams,** former store manager at Leeville, takes over the Lafayette store. **William F. Wheeler** is the new Division Production Equipment specialist for the Los Angeles Division office. **Walter M. Golden,** D+B specialist, has been moved from Duncan, Okla., to County Line, Okla., and **Robert F. Gregg,** Division Oil Country Tubular representative, moved from Tulsa to Denver. **W. H. Ramsdell,** former assistant chief mechanical engineer, has been promoted to manager, Quality Control at the Houston plant. **Harry Hobbs, Jr.,** former division merchandise manager of the Houston Division, was promoted to assistant general merchandise manager at the Dallas general office. **Noble D. Lane,** former district manager at Lafayette, La., was promoted to division manager over the South Texas Division.

Continental-Emsco Changes Name of British Subsidiary

Continental-Emsco Company, a division of The Youngstown Sheet and Tube

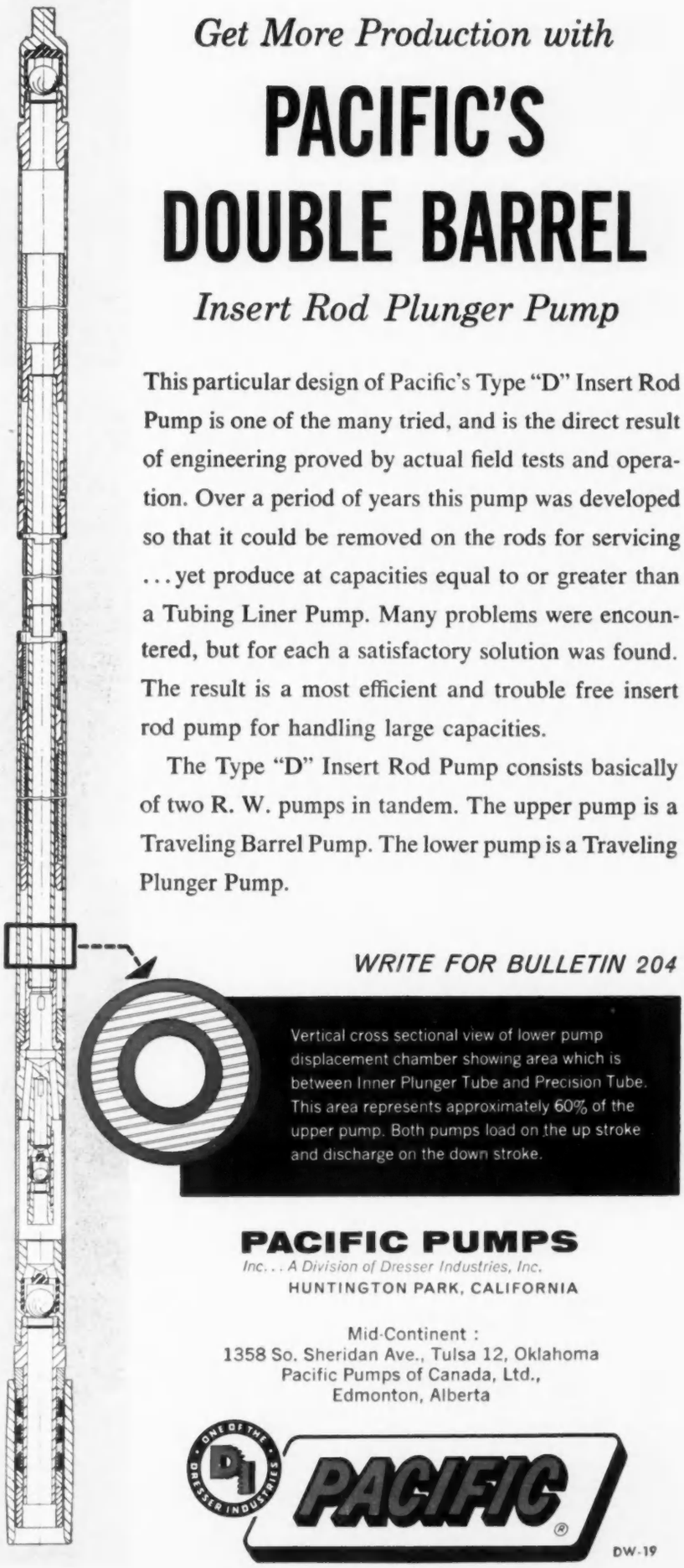
Get More Production with

PACIFIC'S DOUBLE BARREL

Insert Rod Plunger Pump

This particular design of Pacific's Type "D" Insert Rod Pump is one of the many tried, and is the direct result of engineering proved by actual field tests and operation. Over a period of years this pump was developed so that it could be removed on the rods for servicing . . . yet produce at capacities equal to or greater than a Tubing Liner Pump. Many problems were encountered, but for each a satisfactory solution was found. The result is a most efficient and trouble free insert rod pump for handling large capacities.

The Type "D" Insert Rod Pump consists basically of two R. W. pumps in tandem. The upper pump is a Traveling Barrel Pump. The lower pump is a Traveling Plunger Pump.



WRITE FOR BULLETIN 204

Vertical cross sectional view of lower pump displacement chamber showing area which is between Inner Plunger Tube and Precision Tube. This area represents approximately 60% of the upper pump. Both pumps load on the up stroke and discharge on the down stroke.

PACIFIC PUMPS

Inc. . . A Division of Dresser Industries, Inc.

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Pacific Pumps of Canada, Ltd.,
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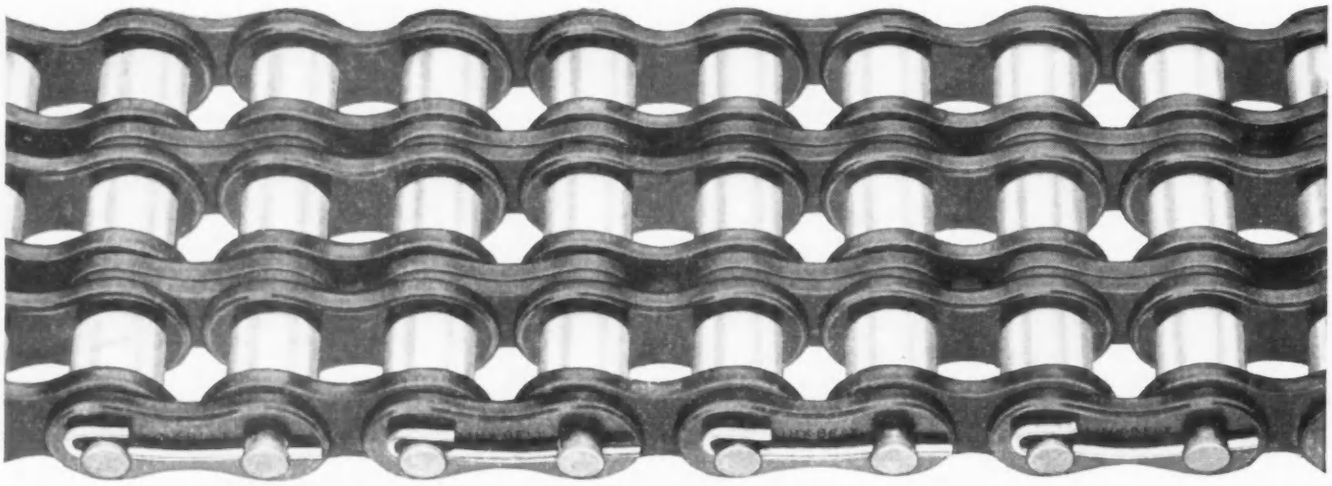
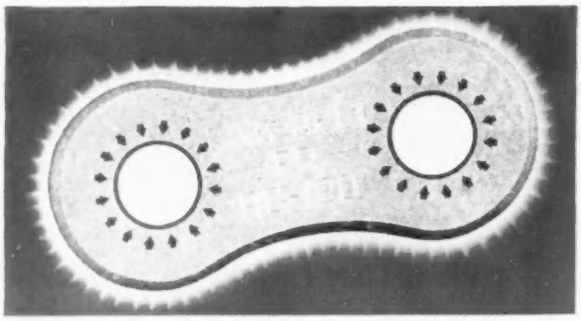
PACIFIC®

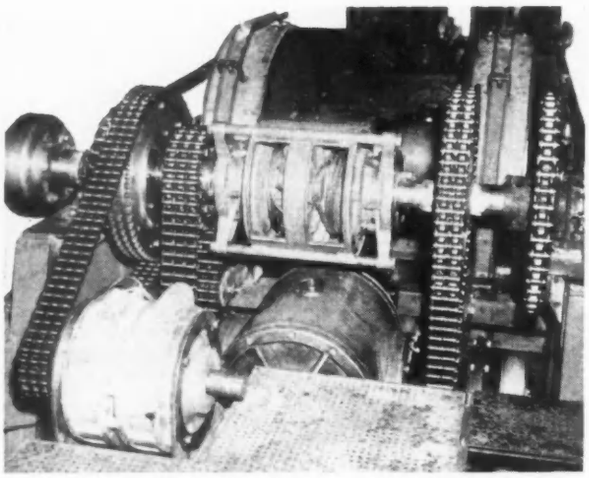
DW-19





Arrows indicate critical areas treated with compressive stresses to improve fatigue resistance.

Fortified against fatigue



COMET PORTABLE DRILLING RIG, built by Cabot Shops, Inc., Pampa, Texas, is equipped with Link-Belt single — and multiple-strand "FR" precision steel roller chain.

LINK-BELT FR® oil field roller chain stands up to tremendous stresses of modern drilling service

The smashing impacts and tortuous stresses met in day-to-day drilling are taken in stride by Link-Belt FR (Fatigue Resistant) roller chain. Through its patented FR process, Link-Belt gives its roller chain *greater dynamic strength*. FR greatly raises the chain's endurance limit by compressing metal around pitch holes—the critical sidebar areas most vulnerable to fatigue failure.

The FR process results from the same design and metallurgical research that has produced many more "extras," all *standard* in Link-Belt oil field roller chains. They include shot-peened rollers, close heat-treat control, Shepherd's Crook Cotters and others. For details, see Catalog **2980.** 15,289

LINK-BELT

ROLLER CHAINS AND SPROCKETS

CATALOG 2880 has full information on all Link-Belt oil field equipment. You can obtain a copy from any leading supply store in the field. Also in Composite Catalog of Oil Field Equipment.

LINK-BELT COMPANY: Indianapolis 6, Houston 1, Dallas 26, Odessa, Tex., New Orleans 6, Shreveport, La., Los Angeles 22 (Montebello), Scarboro (Toronto 13); Export Office, New York 7. Distributors in All Fields.

Suppliers' notes

Company, has announced a change of name for its British subsidiary, headquartered at St. Albans near London.

Formerly known as Emsco Engineering Company, Ltd., the English firm will now operate as Continental-Emsco (G.B.), Ltd. The English plant maintains close engineering contact with home offices in Dallas to assure interchangeability of all British and U. S.-made parts.

The plant was purchased by Emsco Manufacturing Company in 1928, and refurbished with new equipment in 1945. It came under its present system of operation in 1957 when Emsco was merged with Continental Supply Company, a division of Youngstown.

Willis Oil Tool Company Moves to New Facilities

Willis Oil Tool Company has moved into its new plant and office facilities. Formerly located on Pine Avenue, the new location is on Palm Drive in Long Beach, Calif.

Occupying a two-acre site, the new Willis plant-office covers 15,000 square feet providing ample room for research, drafting, phototype development, production and greatly expanded test facilities. The plant production area itself covers over 12,000 square feet and includes more than ample space for engine and turret lathes, milling machines, grinders, drill presses and welding areas.

The new facilities have enabled Willis to speed up all production processes and reduce delivery time. Future expansion can be accomplished within the existing building group.

W. D. Warner

F. W. McFarland

Oklahoma Tool Companies Merged Into Acme Tools, Inc.

Two Oklahoma City tool companies, Acme Oil Tool Company and Great Bend Fishing Tool Company, have merged and become Acme Tool, Inc. The merger was effective March 1.

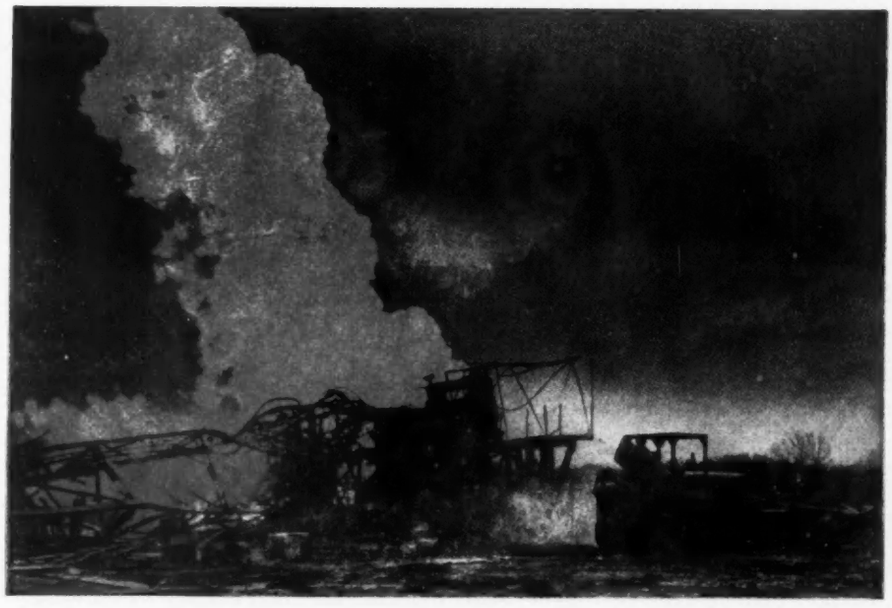
The new organization, Acme Tool, Inc., will offer a more complete line of oil field services, a complete fishing tool rental and engineering service, directional drilling and oil field machine shops. The new company employs approximately 150 people.

All officers of both companies will be active in the new organization. William D. (Bill) Warner, president of Great Bend, is chairman of the board of Acme Tool, Inc. F. W. (Bill) McFarland, president of Acme Oil Tool Company, Inc., is president of the new firm. Harold Sadberry, new executive vice president, is the general manager of all fishing tool operations. He formerly occupied this position with Great Bend. Don Burner is vice president in charge of machine shops. Howard B. Weston, who was secretary of Acme Oil Tool, Inc., has become treasurer of the new company. Eugene P. Ledbetter, attorney and officer of Great Bend, is the new secretary. All officers are members of the board of directors and are stockholders of the company.

Avondale Marine Ways, Inc., Opens Customers' Building

Avondale Marine Ways, Inc., New Orleans, has opened a customers' building to provide customers' representatives with the facilities essential to their individual requirements.

As a result of Avondale's major expansion program last fall, a porcelain enamel building with 8,400 square feet of floor area was erected specifically to provide office space for resident customers and inspectors. Located adjacent to the Engineering and Research building and Avondale's main administration building, the new customers' quarters are convenient to the company's activities.



A "Pit-O-Graf" MIGHT HAVE SAVED THIS WELL

A Pit-O-Graf can give adequate warning to prevent a blowout. But, it must be where the driller can see it, can take advantage of it. Here's what users have to say:

One oil company says — "Although blowout prevention is a matter of concern for the operator, the contractor, and the drilling crews, generally *the driller is the key man.*"

Another company says—"Since a pit level indicator is so important, take these precautions to get the most good out of it: Place the pit level recording instrument at or near *the driller's position on the derrick floor.*"

If the driller's responsibility is not misplaced, then he can recognize the danger signals that precede every blowout. With the Pit-O-Graf record before him, he can intelligently analyze the *rate* of gain or loss of mud as recorded and thereby direct his crew in the orderly control of the situation at hand. In this case the threatened blowout would become *one that does not happen.*

WARREN AUTOMATIC TOOL CO. WACO HOUSTON

WARREN AUTOMATIC TOOL CO.

3915 THARP STREET • HOUSTON, TEXAS

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Lake Charles HEmlock 6-2265 | New Iberia EMerson 9-9862 | Harvey FOrest 6-1441

For more data on advertised products, use Readers' Service Cards, last page

INCREASE PROFITS WITH

REDA
Submergible
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REDA GIVES YOU THESE COST SAVING FEATURES AND DOES THE JOB BETTER!

- Lower cost for installation, operation and maintenance.
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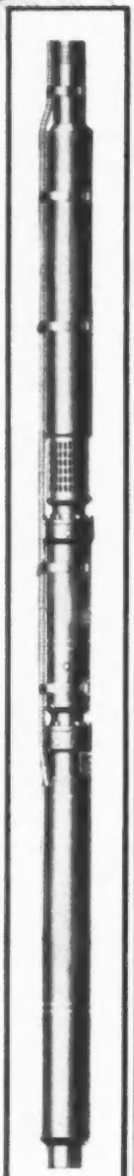
- Corrosion-resistant construction
- Long life — dependable service
- A complete line to meet pumping requirements

and

INVESTMENT COST IS FAR LOWER WHEN YOU CHOOSE REDA FOR YOUR PUMPING NEEDS.



Write or call for more information. Reda engineers will be pleased to assist and help plan your operations.

SIGN OF QUALITY SUBMERGIBLE REDA PUMPS

REDA PUMP CO.
BARTLESVILLE, OKLAHOMA

Manufacturers of submergible motors and pumps for over 35 years — for oil, brine and water wells, gasoline and jet fuel —

SQUEAKS

From the Bull Wheel

"One reason you didn't get our drilling contract—You don't give trading stamps."

Signs of the Time

Like the Scotchman who would not wear his glasses all the time, in order to save them, the State of Nebraska is reported to have erected this sign, "Main highway open for traffic while detour is being repaired."

Maybe Next Time, Doc.

Doctor: "I've examined you thoroughly and I can't seem to find the cause of your illness. It might be due to drinking however."

Patient: "Oh, that's all right, Doc. I'll come back some time when you're sober."

Fashion Note

There will be little change in pockets this year.

Overheard

"My wife and I have had five years of happy marriage, and out of 15 that's not bad at all."

Half and Half

"Yes and no," replied Wally Schmidlapp, when asked if he enjoyed his date with the Siamese twins.

At Your Own Risk

The vacationer, who was in swimming, hollered at the man on shore, "Are you sure there are no crocodiles around here?"

"Absolutely. The sharks scare them away."

Seeing Is Believing

A pink elephant, a green kangaroo and two yellow snakes went into the night club and glanced at the clock as they sat at the bar.

"You're a little early, boys," volunteered the bartender, "he's not here yet."

SECONDARY RECOVERY

PETROLEUM ENGINEERS
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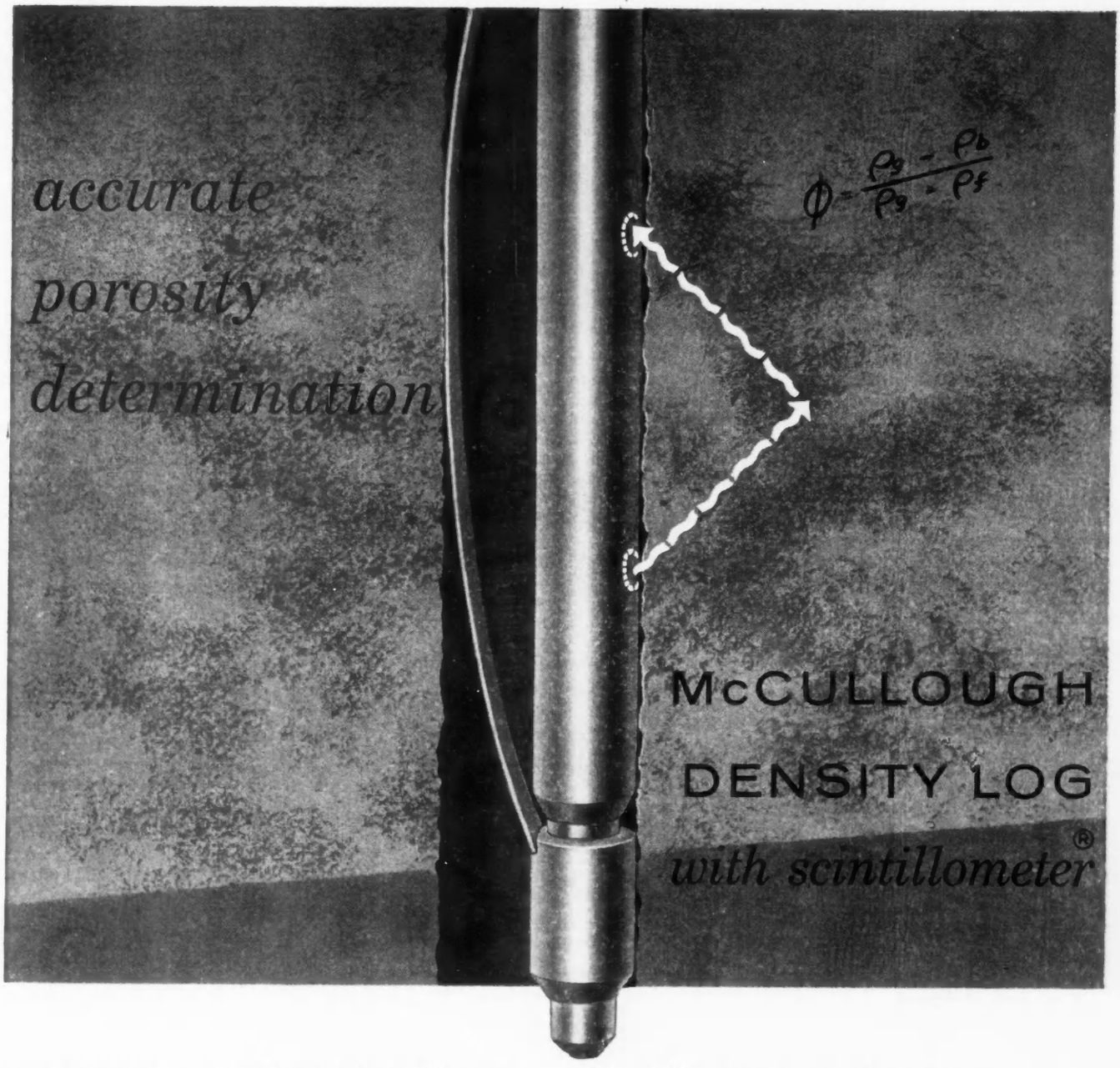

A new advancement in the field of nuclear well logging – McCullough's Density Log accurately measures the bulk density of formations. This rock density is of prime importance in the interpretation of geophysical data. Where grain density values are known, porosity can be determined with accuracy.

The McCullough Density Logger is the only tool of its type that utilizes collimation, the Scintillometer and an energy or pulse height discriminator. By this method, a beam of gamma rays is directed into the formation by the source collimator and back-scattered gamma rays are accepted by the Scintillometer collimator. The discriminator is adjusted for recording gamma rays in the energy band that reflects deep penetration. The numerical intensity of these gamma rays is directly related to the density of the formation.

Check these important features:

- Accurately calibrated in the field with a calibration block of known density.
- Absolute zero is recorded on each log and a linear count scale enables the graphic conversion of counts per second to bulk density for logs run in any well.
- Bulk density, with the grain density of the formation minerals taken into consideration, is in turn graphically converted to accurate porosity values for various types of lithology.
- Responsive to the physical properties of the formation, not its chemical properties except as they relate to density.
- Bore hole fluid and hole size changes are not reflected in the log so long as the instrument maintains adequate contact with the side of the bore hole.
- Charts are provided to compensate for the presence of mud cake in arriving at true formation density.

AVAILABILITY – This service is being made available at our district offices as rapidly as possible. Check with the McCullough representative in your locality.

McCullough TOOL COMPANY

LOS ANGELES • HOUSTON • EDMONTON *Cable Address:* MACTOOL

Fourteen international guests attended the Houston Nomads' April dinner meeting and helped to establish a chapter attendance record for a regular meeting. Standing left to right: George H. Ratcliffe, Asiatic Petroleum; H. J. Clarke, British Petroleum, London; T. E. Ryland, Stewarts & Lloyds, London; V. N. Sovinsky, consulting geologist, Houston; Gabriel de Melo, Drilling & Exploration, Brazil; M. Demoustier, Schlumberger, Caracas; Paul M. Severson, Arrow Drilling, Iraq; Farrokh Ostovar, and Henry Nikubonyad, National Iranian, Iran. Sitting left to right: Jimmie Lloyd, Shell Oil, Maracaibo; Fereydom Afkham, National Iranian, Iran; Harold Lester, Texas Gulf Producing Co., and Dr. J. Brian Eby, consulting geologist, Houston, the two speakers who discussed the oil situation in Libya; and Maurice Piotin, CFPA, Algiers. Guests not shown in the photograph were Jose Mendez, Shell Oil, Maracaibo, and Vinzeno Spezialli and Giovanni Nardelli of Agip, Meneraria, Italy.

Dow's Cleveland Office Occupies New Quarters

The Dow Chemical Company's Cleveland, Ohio, sales office has recently occupied new quarters on the eighteenth floor of the recently completed Illuminating Building.

The office services markets for the company's major product lines, industrial chemicals, plastics, magnesium and agricultural chemicals in northern and central Ohio.

In line with Dow's current modernization program for its sales offices, the Cleveland office makes use of modern, functional furnishings and equipment. To expedite customer service, the entire work area is built around a communications center which relays customer orders to Dow manufacturing locations throughout the country by the Dow private line teletype network.

H. Q. Buck

J. T. Kenneally

J. T. Kenneally Named New HOMCO President

J. T. Kenneally, who has been serving as executive vice president, was appointed president of Houston Oil Field Material Company at a recent meeting of the stockholders. Hugh Q. Buck, who has served as HOMCO president since late 1958, was named chairman of the board. Frederick W. Richmond of New York was named chairman of the executive committee, and C. L. Roach, vice president in charge of domestic operations, also was elected to the board. All other directors were re-elected.

C. L. Roach

At the same meeting, service awards were presented to A. W. Waddill and T. C. Smith, both who have been with HOMCO for 30 years. Waddill is vice president in charge of public relations and special projects, and Smith is director of fishing and cutting tools.

Other officers elected are: Z. C. Ambrose, executive vice president; Roach, vice president, Domestic Operations; Waddill, vice president, Public Relations; George E. Justice, vice president, Manufacturing; H. T. Hamm, secretary-treasurer, Controller; James H. Kerr, Jr., assistant secretary; Lawrence S. Bangser, assistant secretary; M. H. Albert, assistant secretary; Grace G. Scown, assistant treasurer.

WORLD OIL'S Trading Post
CLASSIFIED ADVERTISING

RATES: Regular Classified (undisplayed) set in this size type: 20 cents per word. Minimum charge $4. Blind box address in our care counts six words. Replies forwarded without charge. **Display Classified ads,** set in suitably larger type with ruled border, $13.50 per column inch. Ten percent discount for two or more insertions of same copy in consecutive issues. **All classified ads payable in advance.** Send copy and checks to: Trading Post Classified Section, World Oil, P. O. Box 2608, Houston, Texas.

FOR SALE

• Army surplus applicable drilling and producing. Star 71 repairs 50% off. V-belts in sets B-112-$2.00 each, B-173-$2.50 each, B-210-$3.00, postpaid. All material Army inspected, processed, unused. Write J. Brooke Reed, Fredericktown, Ohio.

MODERN, ATTRACTIVE OFFICE BUILDING

at 1025 S. Shepherd containing 7500 sq. ft. floor space. Located across street River Oaks and two blocks freeway. Formerly occupied by geophysical company. Situated on 85,000 sq. ft. of valuable land which also contains shop and lab buildings. Ideal for oil company, service company, lab, shop, etc. Sale price $350,000. Call JA 8-5360 or write

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SALESMAN WANTED

Well-established successful firm has opening in an expanding sales department for young man looking for an opportunity in sales work. Must be college graduate, not over 33, in good health, ambitious and not afraid of work. Oil industry experience desirable. The man we are looking for will be trained at home office before moving into sales work on basis of salary plus commission incentive and traveling expenses. Our own personnel know of this advertisement. Your reply will be confidential and should be sufficiently complete to merit contacting you for an interview. Address Box 200-W, WORLD OIL, Houston, Texas.

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